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**STATE OF NEW HAMPSHIRE**
**BEFORE THE**
**PUBLIC UTILITIES COMMISSION**

# EnergyNorth Natural Gas, Inc.
# d/b/a Liberty Utilities

## Winter 2012-13 Cost of Gas

## DG 12-_____

## Prefiled Testimony of Ann E. Leary

**August 31, 2012**

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**Q. Ms. Leary, please state your full name and business address.**

A. My name is Ann E. Leary. I am the Manager of Gas Pricing for National Grid Corporate Service LLC. My business address is 40 Sylvan Road, Waltham, Massachusetts 02451.

**Q. As an employee of National Grid, please explain why you are testifying today on behalf of EnergyNorth Natural Gas, Inc?**

A. In accordance with Amended and Restated Transition Services Agreement between National Grid USA and EnergyNorth Natural Gas, Inc. (the "Company"), employees of National Grid or its affiliated companies are providing certain services to the Company, including assistance with matters relating to Cost of Gas proceedings.

**Q. How long have you been employed by National Grid or its affiliates and in what capacities?**

A. In 1985, I joined the Essex County Gas Company as Staff Engineer. In 1987, I became a planning analyst and later became the Manager of Rates. Following the acquisition of Essex by Eastern Enterprises in 1998, I became Manager of Rates for Boston Gas. After Eastern was acquired by KeySpan Corporation in November 2000, I continued on as Manager of Rates for the four KeySpan Energy Delivery New England regulated gas companies, Boston Gas Company, Essex Gas Company, Colonial Gas Company, and EnergyNorth Natural Gas Company. My responsibilities remained the same following the acquisition of KeySpan by National Grid.

**Q. What do your responsibilities as Manager of Pricing include?**

A. As the Manager Pricing, I am responsible for preparing and submitting various regulatory filings with the Massachusetts Department of Public Utilities on behalf of National Grid local gas distribution companies. Prior to the sale of EnergyNorth, I prepared and submitted regulatory filings to the New Hampshire Public Utilities Commission (the "Commission") on behalf of EnergyNorth. These filings include Cost of Gas ("COG") filings, Local Distribution Adjustment Charge ("LDAC") filings and reconciliations, energy conservation, performance-based revenue calculations, lost-base revenues, and exogenous cost filings.

**Q. Please summarize your educational background.**

A. I received a Bachelor of Science in Mechanical Engineering from Cornell University in 1983.

**Q. Have you previously testified in regulatory proceedings?**

A. I have testified in a number of regulatory proceedings before the Commission and the Massachusetts Department of Public Utilities on a variety of rate matters that include: cost allocation studies, rate design, cost of gas adjustment clause proposals, and exogenous cost filings.

**Q. What is the purpose of your testimony?**

A. The purpose of my testimony is to explain the Company's proposed firm sales cost of gas rates for the 2012/13 Winter (Peak) Period and the Company's proposed 2012/13 Local Distribution Adjustment Factor both effective beginning November 1, 2012.

## COST OF GAS FACTOR

**Q. What are the proposed firm sales and firm transportation cost of gas rates?**

A. The Company proposes a firm sales cost of gas rate of $0.6719 per therm for residential customers, $0.6736 per therm for commercial/industrial high winter use customers and $0.6671 per therm for commercial/industrial low winter use customers as shown on Proposed Third Revised Page 87. The Company proposes a firm transportation cost of gas rate of $0.0002 per therm as shown on Proposed First Revised Page 89.

**Q. Would you please explain tariff page Proposed First Revised Page 86 and Proposed Third Revised Page 87?**

**A**. Proposed First Revised Page 86 and Proposed Third Revised Page 87 contain the calculation of the 2012/13 Winter Period Cost of Gas Rate and summarize the Company's forecast of firm gas costs and firm gas sales. As shown on Page 87, the proposed 2012/13 Average Cost of Gas of $0.6719 per therm is derived by adding the Direct Cost of Gas Rate of $0.6279 per therm to the Indirect Cost of Gas Rate of $0.0440 per therm. The estimated total Anticipated Direct Cost of gas, derived on Page 86 and repeated on Page 87, is $48,820,141. The estimated Indirect Cost of Gas, also derived on

Page 86 and repeated on Page 87, is $3,420,439. The Direct Cost of Gas Rate of $0.6279 and the Indirect Cost of Gas Rate of $0.0440 are determined by dividing each of these total cost figures by the projected winter period firm sales volumes of 77,755,617 therms.

To calculate the total Anticipated Direct Cost of Gas, the Company adds a list of allowable adjustments from deferred gas cost accounts to the projected demand and commodity costs for the winter period supply portfolio. These allowable adjustments, shown on Page 86, total $295,808. These adjustments are added to the Unadjusted Anticipated Cost of Gas of $48,524,333 to determine the Total Anticipated Direct Cost of Gas of $48,820,141.

**Q. What are the components of the Unadjusted Anticipated Cost of Gas?**

A. The Unadjusted Anticipated Cost of Gas shown on Proposed First Revised Page 86 consists of the following components:

| | | |
|---|---|---|
| 1. | Purchased Gas Demand Costs | $9,446,057 |
| 2. | Purchased Gas Commodity Costs | $26,630,667 |
| 3. | Storage Demand and Capacity Costs | $1,092,898 |
| 4. | Storage Commodity Costs | $9,121,704 |
| 5. | Produced Gas Cost | $291,366 |
| 6. | Hedge Contract Loss/(Savings) | $1,941,641 |
| | Total | $48,524,333 |

**Q. What are the components of the allowable adjustments to the Cost of Gas?**

A. The allowable adjustments to gas costs, listed on Proposed First Revised Page 86 are as follows:

| | | |
|---|---|---|
| 1. | Prior Period Under Collection | $1,606,569 |
| 2. | Interest | 73,865 |
| 3. | Broker Revenues | (396,197) |
| 4. | Fuel Financing | 109,724 |
| 5. | Transportation COG Revenue | (8,224) |
| 6. | Interruptible Sales Margin | 0 |
| 7. | Capacity Release Margin | (1,130,619) |
| 8. | Fixed Price Administrative Cost | 40,691 |
| | Total Adjustments | $295,808 |

These allowable adjustments are standard accounting adjustments that are made to the deferred gas cost balance through the operation of the Company's cost of gas adjustment clause. Later in this testimony I will discuss the factors contributing to the prior period under collection.

**Q. How does the proposed average cost of gas rate in this filing compare to the average cost of gas rate approved by the Commission in DG 11-192 for the 2011/12 Winter Period?**

A. The average cost of gas rate proposed in this filing is $0.1207 per therm lower than the initial rate of $0.7926 approved by the Commission in Order No. 25,286 dated October 31, 2011 in DG 11-192. This decrease in the rate reflects a decrease in the total cost of gas of approximately $13.3 million or 20% (a $13.1 million decrease in total direct gas

costs and a $0.2 million decrease in indirect gas costs). The $13.1 million decrease in the total direct cost of gas is a result of a $8.8 million decrease in commodity costs, a $2.4 million decrease in demand costs and a $1.9 million decrease in adjustments.

The $8.8 million decrease in commodity costs is due to a $9.0 million decrease in pipeline commodity costs offset by a $0.2 million increase in supplemental costs (underground storage, LNG, and propane). The $9.0 million decrease in pipeline costs is due to a projected decrease in commodity price of $4.3 million and a projected decrease of $4.7 million resulting from decreased pipeline throughput volumes. Total commodity gas costs (including hedges) are projected to be approximately $.0408/therm lower than last year, resulting in a $4.3 million decrease, while pipeline throughput is projected to be down by 8.4 million therms, resulting in a decrease in commodity costs of $4.7 million. The $1.9 million decrease in adjustments reflects a $2.1 million decrease in Prior Period Under Collection, $0.7 million decrease in interruptible sales margin and a $1.0 increase in Broker Revenues.

**Q. How does the proposed firm transportation winter cost of gas rate compare to the rate approved by the Commission for the 2011/12 winter period?**

A. The proposed firm transportation winter cost of gas rate is $0.0002 per therm. The rate approved in DG 11-192 was $0.0000. This increase is largely due to the increase in the net amount to be collected from Transportation customers to the 2011-12 period.

**Q. In the calculation of its firm transportation winter cost of gas rate, has the Company updated the estimated percentage used for pressure support purposes?**

A. No, the Company used for pressure support purposes 9.9% based on the marginal cost study used for the rate design approved in the Settlement Agreement in DG 10-017, that was applied to the Peak 2011/12 Cost of Gas filing.

**Q. What was the actual weighted average firm sales cost of gas rate for the 2011/12 winter period?**

A. The weighted average cost of gas rate was approximately $0.7309 per therm. This was calculated by applying the actual monthly cost of gas rates for November 2011 through April 2012 to the monthly therm usage of a typical residential heating customer using 1,250 therms per year, or 932 therms for the six winter period months, for heat, hot water and cooking.

**PRIOR PERIOD UNDER COLLECTION**

**Q. Please explain the Prior Period Under Collection of $1,719,376.**

A. The Prior Period Under Collection is detailed in the 2011/12 Winter Period Reconciliation Analysis included in Tab 18 of this filing. The $1,719,376 under collection is the sum of the deferred gas cost, bad debt, and working capital balance as of April 30, 2012, including Peak Period costs recovered in May 2012 based on billings for April consumption. The under collection is primarily due to lower sales and sendout

throughput during March and April 2012 due to warmer than normal weather. The Company's April trigger filing was based on normal weather.

**FIXED PRICE OPTION**

**Q. Has the Company established a winter period fixed price pursuant to its Fixed Price Option Program?**

A. Yes, in Order No. 24,515 in docket DG 05-127, dated September 16, 2005, the Commission approved an amendment to the Fixed Price Option Program ("FPO"). In accordance with the approved changes to the FPO, the FPO rates are set at $0.02 per therm higher than the initial proposed COG. Proposed First Revised Page 88 contains the FPO rates for the 2012/13 Winter period, which are $0.6919 per therm for residential customers, $0.6871 per therm for commercial/industrial low winter use customers, and $0.6936 per therm for commercial/industrial high winter use customers. These compare to FPO rates approved for the 2011/12 winter period of $0.8126 per therm for residential customers, $0.8111 per therm for commercial/industrial low winter use customers, and $0.8129 per therm for commercial/industrial high winter use customers. This represents a $0.1207 per therm, or 14.9%, decrease in the residential FPO rate. The impact on the winter period bill of a typical heating customer is a decrease of approximately $153 or 13.2% compared to last winter. The bill impact reflects the implementation of the decrease approved in DG 12-128 effective July 1, 2012 relating to the cast iron/bare steel main replacement program. The estimated winter period bill for a typical residential heating customer opting for the FPO would be approximately $19 or 1.9% higher than

the bill under the proposed cost of rates assuming that the COG is not revised prior to final approval by the Commission and also assuming no monthly adjustments to the COG rate during the course of the winter. Tab 23 contains the historical results of the FPO program as required by Order No. 24,515 issued on September 16, 2005 in DG 05-127.

**HEDGED SUPPLIES**

**Q. Has the Company hedged any of its winter period supplies pursuant to its proposed Natural Gas Price Risk Management Plan?**

A. Yes, it has. As shown in Tab 7, Schedule 7, Page 2, the Company thus far has hedged 2,010,000 Dekatherms (20.1 million therms) at a weighted average fixed price of $4.3890 per Dekatherm. The hedged price reflects the higher cost of gas during the period that the hedged volumes were locked in. The Company shows in Tab 7, Schedule 7, Page 3, that the remaining 920,000 Dekatherms will be hedged at an estimated price of $3.4250 per Dekatherm based on recent NYMEX futures strip prices. The result is a total estimated hedged volume for the winter period of 2,930,000 Dekatherms at a cost of $11,972,792 or approximately $4.0863 per Dth.

**Q. On what dates and at what prices did the Company contract for these supplies?**

A. The Company has eighteen contracts that hedge the price of gas supplies for the 2012/13 Winter Period with prices ranging from $2.78 to $5.5300 per Dekatherms. The contracts date as far back as June 10, 2011 and as recently as July 20, 2012. The contract dates, volumes and prices are listed in Exhibit 7 pages 2 through 4.

**LOCAL DISTRIBUTION ADJUSTMENT CHARGE**

**Q. What are the surcharges that will be billed under the LDAC?**

A. The Company is submitting for approval an LDAC of $0.0258 for the residential non heating class and residential heating class, and $0.0187 for the commercial/industrial bundled sales classes. The surcharges that are billed under the LDAC are the Energy Efficiency Charge, the Environmental Surcharge for Manufactured Gas Plant ("MGP") remediation, the Residential Low Income Assistance Program charge, and the Temporary Rate Reconciliation Amount per DG 10-017 as approved per (1) Order No. 24,109 in DG 02-106, Energy Efficiency for Gas Utilities, (2) Order No. 24,636 in DG 06-032, Energy Efficiency for Gas Utilities, (3) Order No. 24,508 in DG 05-076, and (4) Order No. 25,202 in DG 10-017.

**Q. Please explain the Energy Efficiency Charge.**

A. The Energy Efficiency Charge is designed to recover the projected expenses associated with the Company's energy efficiency programs for Calendar Year 2013 that will be filed with the Commission on September 17, 2012. In the calculation of the Energy Efficiency Factor, the Company has also included the projected prior period over recovery of the Company's Residential and Commercial energy efficiency programs as of October 2012. The Energy Efficiency Charge is also designed to recover performance based incentives associated with the Company's energy efficiency programs during the period January–December 2011 that were filed with the Commission in DE 10-188 on June 21, 2012.

The incentive calculations that are included in this LDAC filing are based on Exhibit C which is provided in Tab 19, Energy Efficiency, page 5.

**Q. What is the proposed Residential Low Income Assistance Program, ("RLIAP"), charge?**

A. The proposed RLIAP charge is $0.0073. It is designed to recover administrative costs, revenue shortfall and the prior period reconciliation adjustment relating to this program. For the 2012/13 Winter Period the Company is providing a 60% base rate discount, consistent with the settlement agreement approved by the Commission in Order No. 24,669 issued on September 22, 2006 in DG 06-120. The current RLIAP factor is designed to recover $1,156,572, of which $1,495,954 is for the revenue shortfall resulting from 5,485 customers receiving a 60% discount off their base rates, $ 8,600 is for estimated administrative costs, and ($347,982) is for the prior year reconciling adjustment.

**Q. In Order No. 24,824 in docket DG 06-122 relating to short term debt issues, the Company agreed to adjust its short term debt limits each year as part of the Company's Winter Period cost of gas filing. Did the Company calculate the short term debt limit for fuel and non-fuel purposes in accordance with this settlement?**

A. Yes, the Company included in Tab 24 the short term debt limit for fuel and non fuel purposes for the 2012-13 period. As shown, the short term limit for fuel inventory

financing for the period November 1, 2011 through October 31, 2012 is calculated to be $15,672,174 and the limit for non-fuel purposes is calculated to be $45,937,039.

**Q. Has the Company updated the Environmental Surcharge (Tariff Page 91)?**

A. Yes, it has. The costs submitted for recovery through the MGP remediation cost recovery mechanism as well as the third party recoveries are presented in the Environmental Cost Summary included in Tab 20 of this filing. The environmental investigation and remediation costs that underlie these expenses are the result of efforts by the Company to respond to its legal obligations with regard to these sites, as described by Ms. Leone in her pre-filed testimony in this proceeding and as set forth in the MGP site summaries included in this filing under Tab 20. The Summary included in Tab 20, pages 1 – 8, shows the remediation cost pools for the Concord, Manchester, Nashua, Dover, Laconia and Keene sites and a General Pool for costs that cannot be directly assigned to a specific site. The filing also includes amounts recovered from insurance companies shown in the section labeled "Cash Recoveries" on the Environmental Cost Summary, pages 9 - 12. These cash recoveries from insurance companies are listed under the headings for the Concord, Laconia, Manchester, Nashua, Dover, and Keene sites. While the recoveries are displayed on the summary by site, they are not exclusive to a particular site. Because the recoveries are often the result of general settlement agreements covering more than one site, there is no basis to determine how much of the settlement amount is associated with a particular site. Page 13 provides the total remediation and recovery costs and collections by year and in total.

In total, the Company has incurred environmental remediation costs of $33,437,414, litigation costs of $9,466,750, and obtained third party cash recoveries of $27,913,628, for a net expense of $14,990,536. To date, the Company has collected $13,237,827 from its Environmental Surcharge factor and base rates.

The 2011-2012 remediation costs that the Company is including in this filing are as follows:

| | |
|---|---|
| Concord (Pool #12) | $81,238 |
| Concord (Pool #9) | $257,528 |
| Laconia (Pool #11) | $269,281 |
| Manchester (Pool #12) | $442,298 |
| Nashua (Pool #11) | $396,411 |
| Keene (Pool#9) | $488 |
| General (Pool #10) | $78,967 |
| Total Remediation | $1,526,211 |
| Litigation Recovery | 0 |
| Litigation Costs | 0 |
| Total 2011-2012 | $1,526,211 |

A summary sheet and detailed backup spreadsheets are provided in Tab 20 of this filing that support the 2011-2012 costs that the Company is submitting. Consistent with past practice, the Company met with the Commission staff earlier this year to update them on

the status of environmental matters. Ms. Leone's testimony describes the Company's activities with regard to all six sites. The Company is prepared to provide additional testimony and exhibits, if necessary, to further support recovery of these amounts after the Commission Staff has completed its review of these costs.

**Q. In DG 11-192, the Company indicated that approximately $78,000 of environmental costs had been embedded in the approved base rate tariffs. How did the Company reflect those revenues in its calculation of its RAC?**

A. The Company has modified its Environmental Cost Summary Schedules in Tab 20 to include the base rate recoveries for the period June 2010 through October 2012. The Company determined these recoveries by multiplying the base rate component associated with the environmental costs by the monthly volumetric throughput during the period June 2010 through October 2012. The Company calculated the environmental rate that was embedded in the base rates by simply dividing the total embedded cost of $78,892 by the 2008-2009 test year normalized throughput level of 148,771,890 therms to derive a factor of $0.0005/therm. Finally, the Company allocated these environmental base rate revenues to those specific pools with outstanding balances.

**Q. Please describe how the Company calculated the Environmental Surcharge included in this filing.**

A. The proposed Manufactured Gas Plant Remediation surcharge for the period beginning November 1, 2012 and ending October 31, 2013 is $0.0011 per therm. This factor will

recover a total of $256,547 in amortized remediation costs less the $78,892 in base rate collections for a net of $177,655. The costs submitted for recovery are presented in the Environmental Cost Summary included in Tab 20 of this filing.

**Q. Does the LDAC include a credit for Interruptible Transportation Margins?**

A. No, the Company has not provided any service under the classification over the past year and therefore has not earned any margins to credit back to sales customers.

**Q. Is the Company proposing to include any Temporary Rate Reconciliation Adjustment approved in Order 25,217 in DG 11-046 relating to the reconciliation for temporary rates from the Company's last base rate case, DG 10-017?**

A. In DG 11-192, the Commission approved recovery on the Temporary Rate Case reconciliation (including rate case expense) adjustment factor of $0.0116 per therm to be assessed to customers during the period November 2011 through October 2012. This factor was developed by dividing the total Temporary Rate Reconciliation Adjustment of $1,899,706 by the projected annual normal throughput of 163,588,592. However, due to weather that was approximately 20% warmer than normal, the Company did not realize the throughput it had projected and as a result did not collect the entire $1,899,706 associated with the Temporary Rate Reconciliation Adjustment. Based on actual collections through July 2012 and projected collections from August 2012 through October 2012, the Company projects that it will collect only $1,468,933. As a result, the

Company is proposing to recover the residual amount of $430,773 ($1,899,706-$1,468,933) from all customers during the period November 2012 through October 2013.

**Q. Has the Company also updated its Company Allowance percentage for the period November 2012-October 2013 in accordance with Section 8.1 of the Company's Delivery Terms and Condition?**

A. Yes, in Schedule 25 the Company has recalculated its Company Allowance for the period November 2011 – October 2012. The Company calculated the Company Allowance of 1.6% based on sendout and throughput data for the twelve month period ending June 2012. This recalculated Company Allowance is proposed to be applied to all supplier deliveries beginning in November 2012.

## CUSTOMER BILL IMPACTS

**Q. What is the estimated impact of the proposed firm sales cost of gas rate and revised LDAC surcharges on an average heating customer's seasonal bill as compared to the rates in effect last year?**

A. The bill impact analysis is presented in Tab 8, Schedule 8 of this filing. Please note that these bill impacts include the base distribution rates approved in Order No. 25,378 in Docket DG 12-128 relating to the cast iron/bare steel main replacement program. The total bill impact for a typical residential heating customer is an decrease of approximately $96, or -8.8%, of which $95, or -14.0%, is from the decrease in the COG and LDAC as compared to the average COG and LDAC for 2011/12 winter season, and a decrease of

$0.3, or -0.1%, resulting from the base rate adjustment in DG 12-128. The total bill impact for a typical commercial/industrial G-41 customer is a decrease of approximately $129, or -7.4%, of which $128, or -12.3 %, is from the decrease in the COG and LDAC as compared to the average COG and LDAC for 2011/12 winter season and a decrease of $0.5, or -0.1%, resulting from the base rate adjustment in DG 12-128. Schedule 8 of this filing provides more detail of the impact of the proposed rate adjustments on heating customers.

**OTHER TARIFF CHANGES**

**Q. Is the Company updating its Delivery Terms and Conditions in the filing?**

A. Yes. The Company is submitting Proposed First Revised Page 155 relating to Supplier Balancing and Peaking Demand Charges and Proposed First Revised Page 156 relating to Capacity Allocation.

**Q. Please describe the changes to Page 155.**

A. In Proposed First Revised Page 155, the Company is updating the Peaking Demand Charge from $18.96 per MMBtu of Peak MDQ to $18.62 per MMBtu of Peak MDQ, a $0.34 decrease and its Supplier Balancing Charges from $0.22 per MMBtu to $0.19 per MMBtu.

This calculation is also presented in Tab 21. It includes the four-page back up Calculations to III Delivery Terms and Conditions Proposed First Revised Page 155, Attachment B – Peaking Demand Charge.

**Q. Please describe the changes to Page 156.**

A. Proposed First Revised Page 156 updates the Capacity Allocator percentages used to allocate pipeline, storage and local peaking capacity to high and low load factor customers under the mandatory capacity assignment requirement for firm transportation service. Tab 22 contains the six-page worksheet that backs up the calculations for the updated allocators.

**Q. Does this conclude your testimony?**

A. Yes, it does.

STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

EnergyNorth Natural Gas, Inc.
d/b/a Liberty Utilities

Winter 2012/2013 Cost of Gas
DG 12-_____

Prefiled Testimony of Francisco C. DaFonte

August 31, 2012

**Q. Mr. DaFonte, please state your name, business address and position with EnergyNorth Natural Gas, Inc. ("EnergyNorth" or "the Company")**

A. My name is Francisco C. DaFonte. My business address is 11 Northeastern Boulevard, Salem, New Hampshire 03079. My title is Director, Energy Procurement.

**Q. Mr. DaFonte, please summarize your educational background, and your business and professional experience.**

A. I attended the University of Massachusetts at Amherst where I majored in Mathematics with a concentration in Computer Science. In the summer of 1985 I was hired by Commonwealth Gas Company (now NSTAR Gas Company), where I was employed primarily as a supervisor in gas dispatch and gas supply planning for nine years. In 1994, I joined Bay State Gas Company (now Columbia Gas of Massachusetts) where I held various positions including Director of Gas Control and Director of Energy Supply Services. At the end of October 2012, I was hired as the Director of Energy Procurement by Liberty Energy Utilities (New Hampshire) Corp. In this capacity, I provide gas procurement services to EnergyNorth.

**Q. Mr. DaFonte, are you a member of any professional organizations?**

A. Yes. I am a member of the Northeast Energy & Commerce Association, the American Gas Association, the National Energy Services Association and the New England Canada Business Council.

**Q. Mr. DaFonte, have you previously testified in regulatory proceedings?**

A. Yes, I have testified in a number of proceedings before the New Hampshire Public Utilities Commission, the Massachusetts Department of Public Utilities, the Maine Public Utilities Commission, the Indiana Utility Regulatory Commission and the Federal Energy Regulatory Commission.

**Q. Mr. DaFonte, what is the purpose of your testimony in this proceeding?**

A. The purpose of this testimony is to summarize the gas supply and firm transportation portfolio and the forecasted sendout requirements for EnergyNorth for the 2012/13 peak season. This information is provided in significantly more detail in the schedules that the Company is filing.

**Q. Mr. DaFonte, would you describe the firm transportation contract portfolio that the Company now holds?**

A. The Company currently holds firm transportation contracts on Tennessee Gas Pipeline (106,833 MMBtu/day) and Portland Natural Gas Transmission (1,000 MMBtu/day) to provide a daily deliverability of 107,833 MMBtu/day to its city gate stations. Schedule 12, page 1 in the Company's filing is a schematic diagram of these contracts, and Schedule 12, page 2 is a table listing these contracts. These contracts provide delivery of natural gas from three sources.

First, the Company holds firm transportation contracts to allow for delivery of up to 8,122 MMBtu/day of Canadian supply. These consist of the following:

- The Company can receive up to 4,000 MMBtu/day of firm Canadian supply from Dawn, Ontario. This supply is delivered to the Company on Company-held firm transportation contracts on Union Gas Limited, TransCanada PipeLines Limited, Iroquois Gas Transmission System, and Tennessee Gas Pipeline ("Tennessee").
- The Company can receive up to 3,122 MMBtu/day of firm Canadian supply from the Canadian/New York border at Niagara Falls, NY. This supply is delivered to the Company on Company-held firm transportation contracts on Tennessee.
- The Company can receive up to 1,000 MMBtu/day of firm Canadian supply from a Company-held firm transportation contract on Portland Natural Gas Transmission System for delivery to its Berlin service territory.

Second, the Company holds the following firm transportation contracts to allow for delivery of up to 71,596 MMBtu/day of domestic supply from the producing and market areas within the United States.

- The Company can receive up to 21,596 MMBtu/day of firm domestic supplies from Texas and Louisiana production areas. These supplies are delivered to the Company on firm transportation contracts on Tennessee.

- The Company can receive up to 50,000 MMBtu/day of firm supply from Tennessee's Dracut receipt point located in Dracut, Massachusetts. This supply is delivered to the Company on two firm transportation contracts on Tennessee.

Third, the Company holds the following firm transportation contracts to allow for delivery of up to 28,115 MMBtu/day of domestic supply from underground storage fields in the New York/Pennsylvania area or the purchase of flowing supply in or downstream of Tennessee Zones 4 and 5.

- The Company can receive up to 19,076 MMBtu/day of firm domestic supplies from its Tennessee FS-MA storage contract. This contract allows for a storage inventory capacity of 1,560,391 MMBtu. These supplies are delivered to the Company on firm transportation contracts on Tennessee.
- The Company can receive up to 9,039 MMBtu/day of firm domestic supplies from its storage contracts with National Fuel Gas Supply Corporation, Honeoye Storage Corporation and Dominion Transmission, Inc.. In aggregate, these contracts allow for a storage inventory capacity of 1,019,740 MMBtu. These supplies are delivered to the Company on a firm transportation contract on Tennessee.

**Q. Have there been any changes in the portfolio of firm transportation contracts that the Company now holds since the Company submitted its 2010/11 Peak Period Cost Of Gas Filing?**

A. The portfolio of firm transportation contracts that the Company currently holds has not changed since the Company's 2011/12 Peak Period Cost of Gas Filing.

**Q. Would you describe the source of gas supplies used with these firm transportation contracts?**

A. The firm transportation contracts that interconnect at the Canadian border source firm gas supplies from both Eastern and Western Canada. The Company's domestic long-haul firm transportation contracts source firm gas supplies primarily from the U.S. Gulf Coast during the winter period and also provide access to natural gas supplies in the Marcellus Shale. Supplies purchased at the Dracut, MA receipt point, on the other hand, can originate from any of a number of locations including Canada, the U.S. Gulf Coast, and LNG terminals.

**Q. Have there been any changes in the portfolio of supply contracts that the Company now holds since the Company submitted its 2011/12 Peak Period Cost Of Gas Filing?**

A. Yes. Typically, the Company negotiates a number of different supply contracts for delivery during the peak period. Since its 2011/12 Peak Period filing, the Company finalized two request for proposals ("RFP") for the upcoming winter for supply: one for its Tennessee Zone 6 firm transportation capacity with Repsol and one for its Canadian firm

transportation capacity interconnecting with Iroquois Gas Transmission, Inc. in Waddington, NY, ("ANE").

In response to its Zone 6 RFP, the Company selected Repsol as the winning bidder. The contract is a capacity management arrangement whereby the Company receives a six-month supply with both baseload and swing nomination provisions. The price for this supply is index based. The index correlates to the receipt point on the Company's firm transportation contract.

The Company is in the process of finalizing its contract for peak-period supply for its ANE supply originating from Dawn, Ontario. The Company intends that this will also be a capacity management arrangement that will provide a firm baseload supply during the peak period with index-based pricing.

With regards to its Tennessee long-haul firm transportation from the U.S. Gulf Coast, the Company anticipates conducting an RFP for a capacity management arrangement coupled with a delivered service during the peak period. As for its Tennessee market-area firm transportation from Niagara, the Company intends to purchase firm gas supplies on a month-to-month basis during the peak period.

As the Commission is aware, the Company's supply-sharing agreement with Granite Ridge Energy, LLC ("Granite Ridge") expired and the Company was not able to negotiate a new contract with Granite Ridge.

Finally, during the 2012 off-peak period, the Company has been injecting supply into its underground storage fields. The Company plans to have all storage fields, with the exception of its Tennessee FS-MA storage, 100 percent full by November 1, 2012; the Tennessee FS-MA field is targeted to be 95 percent full by November 1, 2012. The 5 percent unfilled portion of FS-MA storage provides a buffer which allows the Company operational flexibility to inject some of its Tennessee long-haul supply into storage if needed due to weather fluctuations during the month of November. By December 1, 2012, it is the Company's plan to have all of its storage fields 100 percent full.

**Q. Would you describe the additional sources of gas supply available to the Company that do not require pipeline transportation capacity?**

A. The Company has two additional sources of gas supply available to it.

First, the Company plans to contract with Distrigas for liquid-only supply that can be used to refill its LNG storage tanks during the peak period. Additionally, the Company will be contracting for dedicated LNG trucking in order to refill its LNG storage inventory. Since the Company's LNG storage capability is limited, having dedicated LNG trucks allows the

Company to replenish inventory as it is used, provides supply security for the customers, and enables the Company to adhere to its seven-day storage inventory requirement (Puc 506.03).

Second, when supplies are available and when it is cost-effective, the Company can obtain firm supplies from market participants that are deliverable at the Company's city gate stations.

**Q. Please describe the supplemental gas supply facilities available to the Company?**

A. The Company owns three LNG vaporization facilities in Concord, Manchester and Tilton that have a combined design vaporization rate of approximately 22,800 MMBtu/day but are limited operationally to a combined workable storage capacity of approximately 12,600 MMBtu. Any vaporization that occurs above the workable storage capacity of each facility requires same day trucking refill that, at this time, is not required to satisfy the Company's design day demand. The Company's LNG facilities are refilled with liquid from Distrigas.

Additionally, the Company owns four propane facilities in Amherst, Manchester, Nashua and Tilton that have a combined design vaporization rate of approximately 34,600 MMBtu/day and a combined workable storage capacity of approximately 100,993 MMBtu. Following the 2011/12 peak period, the Company's propane facilities were refilled and they

are ready for the 2012/13 peak period. The Company will also have arrangements in place for its propane trucking needs for the upcoming peak period.

Together, these LNG and propane facilities provide the Company and its customers with necessary system pressure support during peak days as well as a critical gas supply source to meet design day requirements. These facilities contribute to the Company's reliable, flexible and least-cost resource portfolio.

**Q. Mr. DaFonte, what was the source of the projected sendout requirements and costs used in this filing?**

A. As in prior cost of gas filings, the Company used projected sendout requirements and costs from its internal budgets and forecasts.

**Q. Would you please describe the forecasted sendout requirements for the peak period of 2012/13?**

A. Schedule 11A of the Company's filing shows the Company's forecasted sendout requirements for sales customers of 79,988,370 therms over the period November 1, 2012 through April 30, 2013 under normal weather conditions which is down 6.2 percent from last year's forecasted value of 85,279,059 therms for the period November 1, 2011 through April 30, 2012. In comparison, the normalized actual sendout to sales customers for the

November 1, 2011 through April 30, 2012 period was 77,928,952 therms (Reconciliation Filing, Summary Page 5, 'Total Volume Weather Variance,' Column B).

Schedule 11B shows the Company's forecasted sendout requirements for sales customers of 88,940,431 therms over the period November 1, 2012 through April 30, 2013 under design weather conditions, down 4.5 percent from last year's forecasted value of 93,105,329 therms for the period November 1, 2011 through April 30, 2012. For the current peak period forecast, design weather requirements are 11.2 percent greater than normal sendout requirements for weather that is 8.6 percent colder than normal.

In Schedule 11C, the Company summarizes the normal and design year sendout requirements, the seasonally-available contract quantities, and the utilization rates of its pipeline firm transportation and storage contracts.

Schedule 11D shows the Company's forecasted design day sendout for sales customers for the upcoming 2012/13 winter of 1,133,557 therms, up 1.5 percent from last year's figure of 1,116,671 therms.

**Q. Does this conclude your direct prefiled testimony in this proceeding?**

A. Yes, it does.

**STATE OF NEW HAMPSHIRE**
**BEFORE THE**
**PUBLIC UTILITIES COMMISSION**

**Re: EnergyNorth Natural Gas, Inc.**
**d/b/a Liberty Utilties**

**Winter 2012-2013 Cost of Gas**

**Docket No. DG 12-_____**

# Pre-filed Direct Testimony of Michele V. Leone on behalf of EnergyNorth Natural Gas, Inc. d/b/a Liberty Utilities

**August 31, 2012**

## I. BACKGROUND

**Q.** Please provide your name, job title and job description.

**A.** My name is Michele Leone. I am the Manager of the New England and Upstate New York Site Investigation and Remediation Program for National Grid. I am responsible for overseeing the management of the investigation and remediation of MGP sites for National Grid's Massachusetts, Rhode Island and Upstate New York affiliates and am providing site investigation and remediation services to EnergyNorth Natural Gas, Inc. d/b/a Liberty Utilities ("ENGI" or the "Company") pursuant to the July 3, 2012 Amended and Restated Transition Services Agreement between National Grid USA and ENGI.

**Q.** Please describe your educational and professional background.

**A.** I hold a Bachelor of Science in Environmental Engineering from Syracuse University, and a Master of Science in Engineering in Environmental Engineering from the University of Michigan at Ann Arbor. I have been employed by National Grid since December 2000 in the Site Investigation and Remediation Group, managing the investigation and remediation of MGP sites. Prior to my employment by National Grid, I held the position of Project Manager for an environmental consulting firm, with responsibility for the investigation and remediation of numerous hazardous waste sites and for providing technical support to expert witnesses in litigation cases.

**Q.** What is the purpose of your testimony?

**A**. The purpose of my testimony is to discuss the status of ENGI's site investigation and remediation efforts at various MGP sites in New Hampshire, to briefly

describe the MGP-related activities performed by the various contractors and consultants, to discuss the costs for which the Company is seeking rate recovery, and to describe the status of the Company's efforts to seek reimbursement for MGP related liabilities from third parties. My testimony is intended to update the information provided by the Company in prior cost of gas proceedings. The costs associated with these investigations and remediation efforts and certain of the amounts recovered from third parties are included in the schedules and other data prepared by Ms. Leary as part of the Company's cost of gas filing.

**STATUS OF INVESTIGATION AND REMEDIATION ACTIVITIES**

**Q.** Will you please briefly describe the status of each of the Company's MGP sites?

**A.** Rather than reviewing each of these sites in a question and answer format, consistent with past practice, the description of the status of investigation and remediation efforts at each site as well as the various efforts to recover the site investigation and remediation costs from third parties are summarized in materials included with Tab 20 of the Company's filing. These summaries follow the format that has previously been agreed upon in discussions between the Company and Commission staff. In addition, as previously ordered by the Commission, in July 2012, the Company held what has been an annual technical session with the Commission staff and the Office of Consumer Advocate to keep them apprised of the status of site investigation and remediation efforts, as well as cost recovery efforts against third parties.

**Q.** In 2004, the Company began an investigation of an area referred to generally as Lower Liberty Hill. Please briefly describe the current status of the Company's

investigation at Lower Liberty Hill and any significant events over the course of the past year.

**A.** Lower Liberty Hill is a disposal area associated with the former Laconia MGP. The disposal area is located in what is now a residential neighborhood in Gilford. The Company completed investigation activities at Lower Liberty Hill in 2007 and the results indicate that soil and groundwater contamination from MGP waste products have impacted locations formerly occupied by four residential properties and a portion of an abutting stream. These impacts are primarily located in sub-surface soils, and in deep groundwater. No drinking water impacts have been found. A Remedial Action Plan ("RAP") was submitted to NHDES in February 2007, which recommended a remedial alternative consisting of a subsurface containment wall, limited soil removal and an impermeable cap. In September 2007, NHDES, responded to the February 2007 RAP and required the Company to evaluate additional remedial alternatives that included further soil removal. In November 2007, the Company submitted RAP Addendum No. 1 to NHDES. The revised plan recommended a remedial alternative that included construction of a subsurface containment wall, removal of tar-saturated soils to a depth of approximately 45 feet, and installation of an impermeable cap on the four residential properties owned by the Company. On February 29, 2008, NHDES issued a letter to the Company indicating that it had reached a preliminary determination that the remedy recommended in the November 2007 RAP met the NHDES requirements and that a final decision would be reached following a public meeting and comment period. Following a public meeting in March and a

six week public comment period, NHDES issued a letter on June 26, 2008, deferring its final decision on the recommended remedial alternative for the Lower Liberty Hill site pending further data analysis following the development of a scope of work prepared after consultations between NHDES, the Town of Gilford and the Company. In 2008 and 2009, technical representatives from the Company, the Town of Gilford, the Liberty Hill neighborhood and NHDES met several times to discuss the comments provided to NHDES during the public comment period, the scope of groundwater modeling to be performed, additional limited data collection, and the results of the modeling and data collection conducted in late 2008 and 2009. Based on the results of the modeling, NHDES requested that the Company submit a revised Remedial Action Plan to evaluate the technical changes from the modeling event.

On August 17, 2009, the Company submitted Remedial Action Plan Addendum No. 2 to NHDES which revised the remediation option recommended in November 2007 to include low flow groundwater extraction and treatment. In October 2010, NHDES issued a Preliminary Decision on Remedial Action Plan Addendum No. 2, in which NHDES indicated that it did not concur with the Company's recommended remedial alternative and further recommended the complete removal of coal tar-impacted soils at the site. The Company attended a NHDES public meeting in November 2010 and submitted a comment letter to NHDES in January 2011 further explaining the Company's rationale for its recommended remedial alternative for the site and discussing why the Company believes that its recommendation should be adopted by NHDES. In November

2011, NHDES issued a Final Decision indicating that NHDES did not concur with the remedy recommended by the Company and selecting the full removal alternative as the remedy for the site. In December 2011, the Company appealed the Final Decision with the New Hampshire Hazardous Waste Council. The appeal process is on-going. The hearing on the appeal will be scheduled after January 3, 2013.

**Q.** Please briefly describe the current status of the Company's remediation work at the Manchester MGP.

**A.** In June 2008, the Company remediated the Merrimack River portion of the site by dredging approximately 9,000 cubic yards of coal tar impacted sediments from the river. The river dredging activities were substantially complete in late 2007 and final restoration activities were completed in May 2008. A Final Remedial Action Implementation Report documenting the sediment remediation activities was submitted to NHDES in August 2008. Pre-design investigations in support of preparation of a Remedial Action Plan for the upland portion of the site were performed between 2007 and 2010, including additional site characterization, coal tar recovery pilot testing and coal tar mobility assessment and modeling. In June 2010, the Company submitted a Remedial Action Plan for the upland portion of the site to NHDES which recommended source removal, coal tar recovery and installation of a barrier wall proximate to the river. In April 2011, NHDES approved the upland Remedial Action Plan and requested that the Company proceed with the additional investigation activities recommended in the June 2010 Remedial Action Plan. These additional investigation activities were performed

off-property in late 2011; the on-property investigation work was initiated in Spring 2012 and is on-going. A Remedial Design Report for the off-property impacts is currently being finalized.

**Q.** Please briefly describe the current status of the Company's remediation work at the Concord MGP.

**A**. The Company began investigation activities at the Concord MGP site in late 2004. Following initial investigation activities, NHDES requested that the Company submit a supplemental scope of work to complete the delineation of MGP-related impacts on and off site. In late 2008, the Company implemented the 2007 NHDES-approved scope of work. In September 2009, the Company submitted a Supplemental Site Investigation Report to NHDES documenting NHDES-approved additional investigation activities at the site performed between 2006 and 2009. NHDES approved the report in February 2010 and directed that certain additional activities be performed, including removal of the contents of certain on-site structures and certain investigation activities outside the boundaries of the Company's property. An Initial Response Work Plan for the structure work was submitted in July 2010 and approved by NHDES in August 2010. The work was completed in June 2011. The Company also submitted a Supplemental Data Collection Work Plan in August 2010 for the additional investigation work requested by NHDES. NHDES approved of the Work Plan on September 16, 2010 (modified with NHDES in November 2011). These investigation activities were completed in July 2012.

With regard to the pond that is located near Exit 13 on Interstate 93, down-gradient from the MGP, when the pond was remediated in 1999, NHDES required that the northern portion remain untouched, allowing for storm water input to the pond, with the knowledge that some contamination remained and might require remediation in the future. In 2006, NHDES requested that the Company address the residual contamination in the pond. Following the completion of additional investigation activities of this portion of the site, the Company submitted to NHDES an Interim Data Collection Report in September 2006, a Conceptual Remedial Design in March 2007, and a Presumptive Remedy Approval Request in March 2009. In May 2009, NHDES granted the Presumptive Remedy Approval allowing for the design and implementation of a cap over the pond sediments to move forward. The proposed remedial work is to be performed on city-owned land and within a NHDOT right-of-way; therefore the Company is working with these parties to come to agreement on the design features, negotiate access, and clarify the responsibilities of the three parties.

**Q.** Please briefly describe the current status of the Company's remediation work at the Nashua MGP.

**A.** In November 2007, the Company submitted and NHDES approved a work plan for a coal tar recovery pilot test at the Nashua MGP site. In June 2008, the Company installed six extraction wells for pilot testing at the site. The Company completed construction of the coal tar recovery system and it began operating in November 2009. To date, 198 gallons of coal tar (also referred to as "DNAPL" or Dense Non-Aqueous Phase Liquid) have been recovered. In September 2010, the

Company submitted an Installation Summary and DNAPL Recovery Pilot test summary report to NHDES recommending that DNAPL extraction activities continue. In addition, the Company submitted a work plan to NHDES in October 2010 for an off-site groundwater investigation program to support the delineation of a Groundwater Management Zone. This work plan was approved by NHDES on November 5, 2010. Following access negotiations and environmental permitting for this investigation (completed in June 2011), the work was performed between October and December 2011. Data analysis is on-going. In addition, two groundwater sampling rounds were conducted.

**Q**. What other MGP investigation and remediation activity has the Company undertaken in the last year?

**A**. Lower Liberty Hill, Manchester, Concord and Nashua are the four areas where there is significant activity involving the Company. There is little or no activity to report at the Keene or Dover locations at this time. As I mentioned previously, the summaries included in the Company's cost of gas filing provide additional detail regarding all of the Company's former MGP sites.

## III STATUS OF INSURANCE COVERAGE LITIGATION

**Q.** Have there been any recent significant developments in the Company's efforts to seek contribution from its insurance carriers that you wish to discuss?

**A.** No. Insurance recovery efforts are mostly complete with respect to all of the Company's former MGP sites. With respect to Liberty Hill, insurance carriers have been placed on notice of a potential claim, but no litigation has been initiated.

184 **Q.** Does this conclude your direct testimony?

185 **A.** Yes, it does.

**Filed Tariff Sheets**

Proposed Third Revised Page 1
Check Sheet

Proposed Third Revised Page 3
Check Sheet

Proposed First Revised Page 5
Check Sheet

Proposed Third Revised Page 76
Firm Rate Schedules

Proposed First Revised Page 86
Anticipated Cost of Gas

Proposed Third Revised Page 87
Calculation of Firm Sales Cost of Gas Rate

Proposed First Revised Page 88
Calculation of Firm Sales Cost of Gas Rate

Proposed First Revised Page 89
Calculation of Firm Transportation Cost of Gas Rate

Proposed First Revised Page 91
Environmental Surcharge - Manufactured Gas Plants

Proposed First Revised Page 92
Rate Case Expense

Proposed First Revised Page 94
Local Distribution Adjustment Charge Calculation (LDAC)

Proposed First Revised Page 155
Attachment B - Schedule of Administrative Fees and Charges

Proposed First Revised Page 156
Attachment C - Capacity Allocators

## CHECK SHEET

The title page and pages 1-94 inclusive of this tariff are effective as of the date shown on the individual tariff pages.

| *Page* | *Revision* |
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| 1 | Third Revised |
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| 3 | Third Revised |
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| 5 | First Revised |
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| 76 | Third Revised |
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| 84 | Original |
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| 86 | First Revised |
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The title page and pages 1-94 inclusive of this tariff are effective as of the date shown on the individual tariff pages.

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**II RATE SCHEDULES**
**FIRM RATE SCHEDULES**

| | Winter Period | | | | Summer Period | | | |
|---|---|---|---|---|---|---|---|---|
| | Delivery Charge | Cost of Gas Rate Page 87 | LDAC Page 94 | Total Rate | Delivery Charge | Cost of Gas Rate Page 87 | LDAC Page 94 | Total Rate |
| **Residential Non Heating - R-1** | | | | | | | | |
| Customer Charge per Month per Meter | $11.97 | | | $ 11.97 | $ 11.97 | | | $ 11.97 |
| All therms | $ 0.1582 | $ 0.6719 | $ 0.0258 | $ 0.8559 | $ 0.1582 | $ 0.5403 | $ 0.0693 | $ 0.7678 |
| **Residential Heating - R-3** | | | | | | | | |
| Customer Charge per Month per Meter | $17.31 | | | $ 17.31 | $ 17.31 | | | $ 17.31 |
| Size of the first block | 100 therms | | | | 20 therms | | | |
| Therms in the first block per month at | $ 0.2739 | $ 0.6719 | $ 0.0258 | $ 0.9716 | $ 0.2739 | $ 0.5403 | $ 0.0693 | $ 0.8835 |
| All therms over the first block per month at | $ 0.2263 | $ 0.6719 | $ 0.0258 | $ 0.9240 | $ 0.2263 | $ 0.5403 | $ 0.0693 | $ 0.8359 |
| **Residential Heating - R-4** | | | | | | | | |
| Customer Charge per Month per Meter | $6.92 | | | $ 6.92 | $ 6.92 | | | $ 6.92 |
| Size of the first block | 100 therms | | | | 20 therms | | | |
| Therms in the first block per month at | $ 0.1096 | $ 0.6719 | $ 0.0258 | $ 0.8073 | $ 0.1096 | $ 0.5403 | $ 0.0693 | $ 0.7192 |
| All therms over the first block per month at | $ 0.0905 | $ 0.6719 | $ 0.0258 | $ 0.7882 | $ 0.0905 | $ 0.5403 | $ 0.0693 | $ 0.7001 |
| **Commercial/Industrial - G-41** | | | | | | | | |
| Customer Charge per Month per Meter | $40.74 | | | $ 40.74 | $ 40.74 | | | $ 40.74 |
| Size of the first block | 100 therms | | | | 20 therms | | | |
| Therms in the first block per month at | $ 0.3251 | $ 0.6736 | $ 0.0187 | $ 1.0174 | $ 0.3251 | $ 0.5411 | $ 0.0493 | $ 0.9155 |
| All therms over the first block per month at | $ 0.2114 | $ 0.6736 | $ 0.0187 | $ 0.9037 | $ 0.2114 | $ 0.5411 | $ 0.0493 | $ 0.8018 |
| **Commercial/Industrial - G-42** | | | | | | | | |
| Customer Charge per Month per Meter | $122.22 | | | $ 122.22 | $ 122.22 | | | $ 122.22 |
| Size of the first block | 1000 therms | | | | 400 therms | | | |
| Therms in the first block per month at | $ 0.3038 | $ 0.6736 | $ 0.0187 | $ 0.9961 | $ 0.3038 | $ 0.5411 | $ 0.0493 | $ 0.8942 |
| All therms over the first block per month at | $ 0.2007 | $ 0.6736 | $ 0.0187 | $ 0.8930 | $ 0.2007 | $ 0.5411 | $ 0.0493 | $ 0.7911 |
| **Commercial/Industrial - G-43** | | | | | | | | |
| Customer Charge per Month per Meter | $524.53 | | | $ 524.53 | $ 524.53 | | | $ 524.53 |
| All therms over the first block per month at | $ 0.1866 | $ 0.6736 | $ 0.0187 | $ 0.8789 | $ 0.0854 | $ 0.5411 | $ 0.0493 | $ 0.6758 |
| **Commercial/Industrial - G-51** | | | | | | | | |
| Customer Charge per Month per Meter | $40.74 | | | $ 40.74 | $ 40.74 | | | $ 40.74 |
| Size of the first block | 100 therms | | | | 100 therms | | | |
| Therms in the first block per month at | $ 0.1740 | $ 0.6671 | $ 0.0187 | $ 0.8598 | $ 0.1740 | $ 0.5388 | $ 0.0493 | $ 0.7621 |
| All therms over the first block per month at | $ 0.1123 | $ 0.6671 | $ 0.0187 | $ 0.7981 | $ 0.1123 | $ 0.5388 | $ 0.0493 | $ 0.7004 |
| **Commercial/Industrial - G-52** | | | | | | | | |
| Customer Charge per Month per Meter | $122.22 | | | $ 122.22 | $ 122.22 | | | $ 122.22 |
| Size of the first block | 1000 therms | | | | 1000 therms | | | |
| Therms in the first block per month at | $ 0.1683 | $ 0.6671 | $ 0.0187 | $ 0.8541 | $ 0.1236 | $ 0.5388 | $ 0.0493 | $ 0.7117 |
| All therms over the first block per month at | $ 0.1142 | $ 0.6671 | $ 0.0187 | $ 0.8000 | $ 0.0712 | $ 0.5388 | $ 0.0493 | $ 0.6593 |
| **Commercial/Industrial - G-53** | | | | | | | | |
| Customer Charge per Month per Meter | $539.80 | | | $ 539.80 | $ 539.80 | | | $ 539.80 |
| All therms over the first block per month at | $ 0.1201 | $ 0.6671 | $ 0.0187 | $ 0.8059 | $ 0.0574 | $ 0.5388 | $ 0.0493 | $ 0.6455 |
| **Commercial/Industrial - G-54** | | | | | | | | |
| Customer Charge per Month per Meter | $539.80 | | | $ 539.80 | $ 539.80 | | | $ 539.80 |
| All therms over the first block per month at | $ 0.0415 | $ 0.6671 | $ 0.0187 | $ 0.7273 | $ 0.0224 | $ 0.5388 | $ 0.0493 | $ 0.6105 |

**Anticipated Cost of Gas**

**PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2012 THROUGH APRIL 30, 2013**
**(REFER TO TEXT ON IN SECTION 16 COST OF GAS CLAUSE)**

| (Col 1) | (Col 2) | (Col 3) |
|---|---|---|
| **ANTICIPATED DIRECT COST OF GAS** | | |
| **Purchased Gas:** | | |
| Demand Costs: | $ 9,446,057 | |
| Supply Costs: | 26,630,667 | |
| **Storage Gas:** | | |
| Demand, Capacity: | $ 1,092,898 | |
| Commodity Costs: | 9,121,704 | |
| **Produced Gas:** | 291,366 | |
| **Hedged Contract (Saving)/Loss** | 1,941,641 | |
| **Hedge Underground Storage Contract (Saving)/Loss** | - | |
| **Unadjusted Anticipated Cost of Gas** | | $ 48,524,333 |
| **Adjustments:** | | |
| Prior Period (Over)/Under Recovery (as of 05/01/12) | $ 1,606,569 | |
| Interest | 73,865 | |
| Prior Period Adjustments | - | |
| Broker Revenues | (396,197) | |
| Refunds from Suppliers | - | |
| Fuel Financing | 109,724 | |
| Transportation CGA Revenues | (8,224) | |
| Interruptible Sales Margin | - | |
| Capacity Release and Off System Sales Margins | (1,130,619) | |
| Hedging Costs | - | |
| Fixed Price Option Administrative Costs | 40,691 | |
| **Total Adjustments** | | 295,808 |
| **Total Anticipated Direct Cost of Gas** | | $ 48,820,141 |
| **Anticipated Indirect Cost of Gas** | | |
| **Working Capital:** | | |
| Total Unadjusted Anticipated Cost of Gas 11/01/12 - 04/30/13) | $ 48,524,333 | |
| Working Capital Rate: Lead Lag Days / 365 | 0.0391 | |
| Prime Rate | 3.25% | |
| Working Capital Percentage | 0.127% | |
| Working Capital | $ 61,669 | |
| Plus: Working Capital Reconciliation (Acct 142.20) | (541) | |
| Total Working Capital Allowance | | 61,128 |
| **Bad Debt:** | | |
| Total Unadjusted Anticipated Cost of Gas 11/01/12 - 04/30/13) | $ 48,524,333 | |
| Less: Refunds | - | |
| Plus: Total Working Capital | 61,128 | |
| Plus: Prior Period (Over)/Under Recovery | 1,606,569 | |
| Subtotal | $ 50,192,030 | |
| Bad Debt Percentage | 2.50% | |
| Bad Debt Allowance | $ 1,254,801 | |
| Plus: Bad Debt Reconciliation (Acct 175.52) | 113,348 | |
| Total Bad Debt Allowance | | $ 1,368,148 |
| **Production and Storage Capacity** | | $ 1,980,428 |
| Miscellaneous Overhead (11/01/12 - 04/30/13) | $ 13,170 | |
| Times Winter Sales | 77,826 | |
| Divided by Total Sales | 95,484 | |
| **Miscellaneous Overhead** | | 10,735 |
| **Total Anticipated Indirect Cost of Gas** | | $ 3,420,439 |
| **Total Cost of Gas** | | $ 52,240,580 |

Issued: August 31, 2012
Effective: November 1, 2012

Issued: By_____
Victor D. Del Vecchio
Title: President

**CALCULATION OF FIRM SALES COST OF GAS RATE**
**PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2012 THROUGH APRIL 30, 2013**
**(Refer to Text in Section 16 Cost of Gas Clause)**

| (Col 1) | (Col 2) | (Col 3) |
|---|---|---|
| Total Anticipated Direct Cost of Gas | $ 48,820,141 | |
| Projected Prorated Sales (11/01/12 - 04/30/13) | 77,755,617 | |
| **Direct Cost of Gas Rate** | | $ 0.6279 per therm |
| **Demand Cost of Gas Rate** | $ 10,538,954 | $ 0.1355 per therm |
| **Commodity Cost of Gas Rate** | 37,985,379 | $ 0.4885 per therm |
| **Adjustment Cost of Gas Rate** | 295,808 | $ 0.0038 per therm |
| **Total Direct Cost of Gas Rate** | $ 48,820,141 | $ 0.6279 per therm |
| Total Anticipated Indirect Cost of Gas | $ 3,420,439 | |
| Projected Prorated Sales (11/01/12 - 04/30/13) | 77,755,617 | |
| **Indirect Cost of Gas** | | $ 0.0440 per therm |
| **TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 11/01/12** | | **$ 0.6719 per therm** |

| | | | |
|---|---|---|---|
| **RESIDENTIAL COST OF GAS RATE - 11/01/12** | **COGwr** | **$** | **0.6719 /therm** |

| | | |
|---|---|---|
| Maximum (COG + 25%) | $ | 0.8399 |

| | | | |
|---|---|---|---|
| **COM/IND LOW WINTER USE COST OF GAS RATE - 11/01/12** | **COGwl** | **$** | **0.6671 /therm** |

| | | | |
|---|---|---|---|
| Average Demand Cost of Gas Rate Effective 11/01/12 | $ 0.1355 | | |
| Times: Low Winter Use Ratio (Winter) | 0.9585 | Maximum (COG + 25%) | $ 0.8339 |
| Times: Correction Factor | 1.00680 | | |
| Adjusted Demand Cost of Gas Rate | $ 0.1308 | | |
| Commodity Cost of Gas Rate | $ 0.4885 | | |
| Adjustment Cost of Gas Rate | $ 0.0038 | | |
| Indirect Cost of Gas Rate | $ 0.0440 | | |
| Adjusted Com/Ind Low Winter Use Cost of Gas Rate | $ 0.6671 | | |

| | | | |
|---|---|---|---|
| **COM/IND HIGH WINTER USE COST OF GAS RATE - 11/01/12** | **COGwh** | **$** | **0.6736 /therm** |

| | | | |
|---|---|---|---|
| Average Demand Cost of Gas Rate Effective 11/01/12 | $ 0.1355 | | |
| Times: High Winter Use Ratio (Winter) | 1.0068 | Maximum (COG + 25%) | $ 0.8420 |
| Times: Correction Factor | 1.0068 | | |
| Adjusted Demand Cost of Gas Rate | $ 0.1373 | | |
| Commodity Cost of Gas Rate | $ 0.4885 | | |
| Adjustment Cost of Gas Rate | $ 0.0038 | | |
| Indirect Cost of Gas Rate | $ 0.0440 | | |
| Adjusted Com/Ind High Winter Use Cost of Gas Rate | $ 0.6736 | | |

**II. RATE SCHEDULES**
**CALCULATION OF FIXED WINTER PERIOD COST OF GAS RATE**
**PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2012 THROUGH APRIL 30, 2013**
**(Refer to Text in Section 17(A) Fixed Price Option Program)**

| (Col 1) | (Col 2) | (Col 3) |
|---|---|---|
| Total Anticipated Direct Cost of Gas | $ 48,820,141 | |
| Projected Prorated Sales (11/01/12 - 04/30/13) | 77,755,617 | |
| **Direct Cost of Gas Rate** | | $ 0.6279 per therm |
| **Demand Cost of Gas Rate** | $ 10,538,954 | $ 0.1355 per therm |
| **Commodity Cost of Gas Rate** | 37,985,379 | $ 0.4885 per therm |
| **Adjustment Cost of Gas Rate** | 295,808 | $ 0.0038 per therm |
| **Total Direct Cost of Gas Rate** | $ 48,820,141 | $ 0.6279 per therm |
| Total Anticipated Indirect Cost of Gas | $ 3,420,439 | |
| Projected Prorated Sales (11/01/12 - 04/30/13) | 77,755,617 | |
| **Indirect Cost of Gas** | | $ 0.0440 per therm |
| **TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE (11/01/12)** | | **$ 0.6719** |
| **FPO Risk Premium** | | $ 0.0200 |
| **TOTAL PERIOD FIXED PRICE OPTION COST OF GAS RATE EFFECTIVE (11/01/12)** | | **$ 0.6919** |

| | | | |
|---|---|---|---|
| **RESIDENTIAL COST OF GAS RATE - 11/01/12** | **COGwr** | **$ 0.6919** | **/therm** |

| | | | |
|---|---|---|---|
| **COM/IND LOW WINTER USE COST OF GAS RATE - 11/01/12** | **COGwl** | **$ 0.6871** | **/therm** |

| | |
|---|---|
| Average Demand Cost of Gas Rate Effective (11/01/12) | $ 0.1355 |
| Times: Low Winter Use Ratio (Winter) | $ 0.9585 |
| Times: Correction Factor | 1.0068 |
| Adjusted Demand Cost of Gas Rate | $ 0.1308 |
| Commodity Cost of Gas Rate | $ 0.4885 |
| Adjustment Cost of Gas Rate | $ 0.0038 |
| Indirect Cost of Gas Rate | $ 0.0440 |
| Adjusted Com/Ind Low Winter Use Cost of Gas Rate | $ 0.6671 |
| FPO Risk Premium | $ 0.0200 |
| | $ 0.6871 |

| | | | |
|---|---|---|---|
| **COM/IND HIGH WINTER USE COST OF GAS RATE -11/01/12** | **COGwh** | **$ 0.6936** | **/therm** |

| | |
|---|---|
| Average Demand Cost of Gas Rate Effective (11/01/12) | $ 0.1355 |
| Times: High Winter Use Ratio (Winter) | $ 1.0068 |
| Times: Correction Factor | 1.0068 |
| Adjusted Demand Cost of Gas Rate | $ 0.1373 |
| Commodity Cost of Gas Rate | $ 0.4885 |
| Adjustment Cost of Gas Rate | $ 0.0038 |
| Indirect Cost of Gas Rate | $ 0.0440 |
| Adjusted Com/Ind Low Winter Use Cost of Gas Rate | $ 0.6736 |
| FPO Risk Premium | $ 0.0200 |
| | $ 0.6936 |

**NHPUC NO. 7 - GAS**
**LIBERTY UTILITIES**

**Proposed First Revised Page 89**
***Superseding Original Revised PAGE 89***

**II. RATE SCHEDULES**

**Calculation of Firm Transportation Cost of Gas Rate**
**PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2012 THROUGH APRIL 30, 2013**
**(Refer to text in Section 16(Q) Firm Transportation Cost of Gas Clause)**

| (Col 1) | (Col 2) | (Col 3) | (Col 4) |
|---|---|---|---|
| ANTICIPATED COST OF SUPPLEMENTAL GAS SUPPLIES: | | | |
| PROPANE | $ - | | |
| LNG | 291,366 | | |
| TOTAL ANTICIPATED COST OF SUPPLEMENTAL GAS SUPPLIES | 291,366 | | |
| ESTIMATED PERCENTAGE USED FOR PRESSURE SUPPORT PURPOSES | 9.9% | | |
| ESTIMATED COST OF LIQUIDS USED FOR PRESSURE SUPPORT PURPOSES | $ 28,845 | | |
| PROJECTED FIRM THROUGHPUT (THERMS): | | | |
| FIRM SALES | 77,826,455 | 65.4% | |
| FIRM TRANSPORTATION SUBJECT TO FTCG | 41,120,858 | 34.6% | |
| TOTAL FIRM THROUGHPUT SUBJECT TO COST OF GAS CHARGE | 118,947,312 | 100.0% | |
| TRANSPORTATION SHARE OF SUPPLEMENTAL GAS SUPPLIES | 34.6% x | $ 28,845 = | $ 9,972 |
| PRIOR (OVER) OR UNDER COLLECTION | | | (1,888) |
| NET AMOUNT TO COLLECT FROM (RETURNED TO) TRANSPORTATION CUSTOMERS | | | $ 8,084 |
| PROJECTED FIRM TRANSPORTATION THROUGHPUT | | | 41,120,858 |
| FIRM TRANSPORTATION COST OF GAS ADJUSTMENT | | | $0.0002 |

## Environmental Surcharge - Manufactured Gas Plants

**Manfactured Gas Plants**

| | |
|---|---|
| Required annual Environmental increase | $256,547 |
| DG 10-17 Base Rate Revision Collections | ($78,892) |
| Environmental Subtotal | $177,655 |
| Overall Annual Net Increase to Rates | $177,655 |
| Estimated weather normalized firm therms billed for the twelve months ended 10/31/13 - sales and transportation | 158,062,349 therms |
| Surcharge per therm | $0.0011 per therm |
| **Total Environmental Surcharge** | $0.0011 |

## Rate Case Expense/Temporary Rate Reconciliation (RDE) Factor Calculation

### Rate Case Expense Factors for Resdential Customers

| | | |
|---|---|---|
| Rate Case Expense (Balance 07/31/12) | $ | 623,004 |
| Temporary Rate Reconciliation - DG 10-017 | | - |
| Sipulation per Settlement Argument - DG 10-017 | | - |
| Reconciliation DG 08-009 and Merger Incentive DG 06-707 | | - |
| Total Rate Case Expense/Temporary Rate Reconciliation Recoverable | $ | 623,004 |
| OffPeak 2012 Rate Case Expense Factor | $ | 0.0116 |
| OffPeak 2012 Projected Volumes (Aug-Oct) | | 16,967,216 |
| OffPeak 2012 Rate Case Expense Projected Collection (Aug-Oct) | | 197,035 |
| OffPeak 2012 Rate Case Expense Projected Interest (Aug-Oct) | | 4,804 |
| Total Net Rate Case Expense/Temporary Rate Reconciliation Recoverable | | 430,773 |
| Forecasted Annual Throughput Volumes for Residential Customer (A:VOLres) | | 57,541,620 |
| Forecasted Annual Throughput Volumes for Commercial/Industrial Customer (A:VOLc&i) | | 100,520,729 |
| Total Volumes | | 158,062,349 |
| **Rate Case Expense Factor** | $ | 0.0027 |

## Local Distribution Adjustment Charge Calculation

| | | Sales Customers | Transporatation Customers | |
|---|---|---|---|---|
| **Residential Non Heating Rates - R-1** | | | | |
| Energy Efficiency Charge | $0.0147 | | | |
| Demand Side Management Charge | 0.0000 | | | |
| Conservation Charge (CCx) | | $0.0147 | | |
| Relief Holder and pond at Gas Street, Concord, NH | 0.0000 | | | |
| Manufactured Gas Plants | 0.0011 | | | |
| Environmental Surcharge (ES) | | 0.0011 | | |
| Interruptible Transportation Margin Credit (ITMC) | | 0.0000 | | |
| Cost Allowance Adjustment Factor | | 0.0000 | | |
| Rate Case Expense Factor (RCEF) | | 0.0027 | | |
| Residential Low Income Assistance Program (RLIAP) | | 0.0073 | | |
| **LDAC** | | **$0.0258** | | **per therm** |
| **Residential Heating Rates - R-3, R-4** | | | | |
| Energy Efficiency Charge | $0.0147 | | | |
| Demand Side Management Charge | 0.0000 | | | |
| Conservation Charge (CCx) | | $0.0147 | | |
| Relief Holder and pond at Gas Street, Concord, NH | 0.0000 | | | |
| Manufactured Gas Plants | 0.0011 | | | |
| Environmental Surcharge (ES) | | 0.0011 | | |
| Cost Allowance Adjustment Factor | | 0.0000 | | |
| Rate Case Expense Factor (RCEF) | | 0.0027 | | |
| Residential Low Income Assistance Program (RLIAP) | | 0.0073 | | |
| **LDAC** | | **$0.0258** | | **per therm** |
| **Commercial/Industrial Low Annual Use Rates - G-41, G-51** | | | | |
| Energy Efficiency Charge | $0.0076 | | | |
| Demand Side Management Charge | 0.0000 | | | |
| Conservation Charge (CCx) | | $0.0076 | $0.0076 | |
| Relief Holder and pond at Gas Street, Concord, NH | 0.0000 | | | |
| Manufactured Gas Plants | 0.0011 | | | |
| Environmental Surcharge (ES) | | 0.0011 | 0.0011 | |
| Cost Allowance Adjustment Factor | | 0.0000 | 0.0000 | |
| Gas Restructuring Expense Factor (GREF) | | 0.0000 | 0.0000 | |
| Rate Case Expense Factor (RCEF) | | 0.0027 | 0.0027 | |
| Residential Low Income Assistance Program (RLIAP) | | 0.0073 | 0.0073 | |
| **LDAC** | | **$0.0187** | **$0.0187** | **per therm** |
| **Commercial/Industrial Medium Annual Use Rates - G-42, G-52** | | | | |
| Energy Efficiency Charge | $0.0076 | | | |
| Demand Side Management Charge | 0.0000 | | | |
| Conservation Charge (CCx) | | $0.0076 | $0.0076 | |
| Relief Holder and pond at Gas Street, Concord, NH | 0.0000 | | | |
| Manufactured Gas Plants | 0.0011 | | | |
| Environmental Surcharge (ES) | | 0.0011 | 0.0011 | |
| Cost Allowance Adjustment Factor | | 0.0000 | 0.0000 | |
| Gas Restructuring Expense Factor (GREF) | | 0.0000 | 0.0000 | |
| Rate Case Expense Factor (RCEF) | | 0.0027 | 0.0027 | |
| Residential Low Income Assistance Program (RLIAP) | | 0.0073 | 0.0073 | |
| **LDAC** | | **$0.0187** | **$0.0187** | **per therm** |
| **Commercial/Industrial Large Annual Use Rates - G-43, G-53, G-54** | | | | |
| Energy Efficiency Charge | $0.0076 | | | |
| Demand Side Management Charge | 0.0000 | | | |
| Conservation Charge (CCx) | | $0.0076 | $0.0076 | |
| Relief Holder and pond at Gas Street, Concord, NH | 0.0000 | | | |
| Manufactured Gas Plants | 0.0011 | | | |
| Environmental Surcharge (ES) | | 0.0011 | 0.0011 | |
| Cost Allowance Adjustment Factor | | 0.0000 | 0.0000 | |
| Gas Restructuring Expense Factor (GREF) | | 0.0000 | 0.0000 | |
| Rate Case Expense Factor (RCEF) | | 0.0027 | 0.0027 | |
| Residential Low Income Assistance Program (RLIAP) | | 0.0073 | 0.0073 | |
| **LDAC** | | **$0.0187** | **$0.0187** | **per therm** |

ATTACHMENT B
Schedule of Administrative Fees and Charges

| | | | |
|---|---|---|---|
| I. | Supplier Balancing Charge: | $0.19 per MMBtu of Daily Imbalance Volumes | |
| II. | Capacity Mitigation Fee | 15% of the Proceeds from the Marketing of Capacity for Mitigation. Capacity for Mitigation. | |
| III. | Peaking Demand Charge | $18.62 MMBTU of Peak MDQ. | |
| IV. | Company Allowance Calculation (per Schedule 25) | | |
| | | 138,409,150 | Total Sendout - Therms Jul-2011 - Jun-2012 |
| | | 136,259,218 | Total Throughput - Therms Jul-2011 - Jun-2012 |
| | | 2,149,932 | Variance (Sendout - Throughput) |
| | Company Allowance Percentage 2012-13 | 1.6% | Variance / Total Sendout |

ATTACHMENT C

## CAPACITY ALLOCATORS

| Rate Class | | Pipeline | Storage | Peaking | Total |
|---|---|---|---|---|---|
| G-41 | Low Annual /High Winter Use | 38.0% | 21.0% | 41.0% | 100.0% |
| G-51 | Low Annual /Low Winter Use | 49.0% | 17.0% | 34.0% | 100.0% |
| G-42 | Medium Annual / High Winter | 38.0% | 21.0% | 41.0% | 100.0% |
| G-52 | High Annual / Low Winter Use | 49.0% | 17.0% | 34.0% | 100.0% |
| G-43 | High Annual / High Winter | 38.0% | 21.0% | 41.0% | 100.0% |
| G-53 | High Annual / Load Factor < 90% | 49.0% | 17.0% | 34.0% | 100.0% |
| G-54 | High Annual / Load Factor < 90% | 49.0% | 17.0% | 34.0% | 100.0% |

## CHECK SHEET

The title page and pages 1-91 inclusive of this tariff are effective as of the date shown on the individual tariff pages.

| *Page* | *Revision* |
|---|---|
| Title | Original |
| 1 | ~~Second~~ Third Revised |
| 2 | Original |
| 3 | ~~Second~~ Third Revised |
| 4 | Original |
| 5 | ~~Original~~ First Revised |
| 6 | Original |
| 7 | Original |
| 8 | Original |
| 9 | Original |
| 10 | Original |
| 11 | Original |
| 12 | Original |
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| 14 | Original |
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| 16 | Original |
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| 25 | Original |
| 26 | Original |
| 27 | Original |
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| 29 | Original |
| 30 | Original |

## CHECK SHEET (Cont'd)

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| 61 | Original |
| 62 | Original |
| 63 | Original |
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| 65 | Original |
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| 67 | Original |
| 68 | Original |
| 69 | Original |
| 70 | Original |
| 71 | Original |
| 72 | Original |
| 73 | Original |
| 74 | Original |
| 75 | Original |
| 76 | ~~Second~~ Third Revised |
| 77 | Original |
| 78 | Original |
| 79 | Original |
| 80 | Original |
| 81 | Original |
| 82 | Original |
| 83 | Original |
| 84 | Original |
| 85 | Original |
| 86 | ~~Original~~ First Revised |
| 87 | ~~Second~~ Third Revised |
| 88 | ~~Original~~ First Revised |
| 89 | ~~Original~~ First Revised |
| 90 | Original |
| 91 | ~~Original~~ First Revised |
| 92 | ~~Original~~ First Revised |
| 93 | Original |
| 94 | ~~Original~~ First Revised |

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| 126 | Original |
| 127 | Original |
| 128 | Original |
| 129 | Original |
| 130 | Original |
| 131 | Original |
| 132 | Original |
| 133 | Original |
| 134 | Original |
| 135 | Original |
| 136 | Original |
| 137 | Original |
| 138 | Original |
| 139 | Original |
| 140 | Original |
| 141 | Original |
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| 143 | Original |
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| 145 | Original |
| 146 | Original |
| 147 | Original |
| 148 | Original |
| 149 | Original |
| 150 | Original |
| 151 | Original |
| 152 | Original |
| 153 | Original |
| 154 | Original |
| 155 | ~~Original~~ First Revised |
| 156 | ~~Original~~ First Revised |

**II RATE SCHEDULES**
**FIRM RATE SCHEDULES**

| | Winter Period | | | | Summer Period | | | |
|---|---|---|---|---|---|---|---|---|
| | Delivery Charge | Cost of Gas Rate Page 87 | LDAC Page 94 | Total Rate | Delivery Charge | Cost of Gas Rate Page 87 | LDAC Page 94 | Total Rate |
| **Residential Non Heating - R-1** | | | | | | | | |
| Customer Charge per Month per Meter | $ 11.97 | | | $ 11.97 | $ 11.97 | | | $ 11.97 |
| All Therms | $ 0.1582 | $ 0.6719 | $ 0.0258 | $ 0.8559 | $ 0.1582 | $ 0.5403 | $ 0.0693 | $ 0.7678 |
| | ~~$ 0.1582~~ | ~~$ 0.7460~~ | ~~$ 0.0693~~ | ~~$ 0.9735~~ | | | | |
| **Residential Heating - R-3** | | | | | | | | |
| Customer Charge per Month per Meter | $ 17.31 | | | $ 17.31 | $ 17.31 | | | $ 17.31 |
| Size of the first block | 100 therms | | | | 20 therms | | | |
| Therms in the first block per month at | $ 0.2739 | $ 0.6719 | $ 0.0258 | $ 0.9716 | $ 0.2739 | $ 0.5403 | $ 0.0693 | $ 0.8835 |
| | ~~$ 0.2739~~ | ~~$ 0.7460~~ | ~~$ 0.0693~~ | ~~$ 1.0892~~ | | | | |
| All therms over the first block per month at | $ 0.2263 | $ 0.6719 | $ 0.0258 | $ 0.9240 | $ 0.2263 | $ 0.5403 | $ 0.0693 | $ 0.8359 |
| | ~~$ 0.2263~~ | ~~$ 0.7460~~ | ~~$ 0.0693~~ | ~~$ 1.0416~~ | | | | |
| **Residential Heating - R-4** | | | | | | | | |
| Customer Charge per Month per Meter | $ 6.92 | | | $ 6.92 | $ 6.92 | | | $ 6.92 |
| Size of the first block | 100 therms | | | | 20 therms | | | |
| Therms in the first block per month at | $ 0.1096 | $ 0.6719 | $ 0.0258 | $ 0.8073 | $ 0.1096 | $ 0.5403 | $ 0.0693 | $ 0.7192 |
| | ~~$ 0.1096~~ | ~~$ 0.7460~~ | ~~$ 0.0693~~ | ~~$ 0.9249~~ | | | | |
| All therms over the first block per month at | $ 0.0905 | $ 0.6719 | $ 0.0258 | $ 0.7882 | $ 0.0905 | $ 0.5403 | $ 0.0693 | $ 0.7001 |
| | ~~$ 0.0905~~ | ~~$ 0.7460~~ | ~~$ 0.0693~~ | ~~$ 0.9058~~ | | | | |
| **Commercial/Industrial - G-41** | | | | | | | | |
| Customer Charge per Month per Meter | $ 40.74 | | | $ 40.74 | $ 40.74 | | | $ 40.74 |
| Size of the first block | 100 therms | | | | 20 therms | | | |
| Therms in the first block per month at | $ 0.3251 | $ 0.6736 | $ 0.0187 | $ 1.0174 | $ 0.3251 | $ 0.5411 | $ 0.0493 | $ 0.9155 |
| | ~~$ 0.3251~~ | ~~$ 0.7463~~ | ~~$ 0.0493~~ | ~~$ 1.1207~~ | | | | |
| All therms over the first block per month at | $ 0.2114 | $ 0.6736 | $ 0.0187 | $ 0.9037 | $ 0.2114 | $ 0.5411 | $ 0.0493 | $ 0.8018 |
| | ~~$ 0.2114~~ | ~~$ 0.7463~~ | ~~$ 0.0493~~ | ~~$ 1.0070~~ | | | | |
| **Commercial/Industrial - G-42** | | | | | | | | |
| Customer Charge per Month per Meter | $ 122.22 | | | $ 122.22 | $ 122.22 | | | $ 122.22 |
| Size of the first block | 1000 therms | | | | 400 therms | | | |
| Therms in the first block per month at | $ 0.3038 | $ 0.6736 | $ 0.0187 | $ 0.9961 | $ 0.3038 | $ 0.5411 | $ 0.0493 | $ 0.8942 |
| | ~~$ 0.3038~~ | ~~$ 0.7463~~ | ~~$ 0.0493~~ | ~~$ 1.0994~~ | | | | |
| All therms over the first block per month at | $ 0.2007 | $ 0.6736 | $ 0.0187 | $ 0.8930 | $ 0.2007 | $ 0.5411 | $ 0.0493 | $ 0.7911 |
| | ~~$ 0.2007~~ | ~~$ 0.7463~~ | ~~$ 0.0493~~ | ~~$ 0.9963~~ | | | | |
| **Commercial/Industrial - G-43** | | | | | | | | |
| Customer Charge per Month per Meter | $ 524.53 | | | $ 524.53 | $ 524.53 | | | $ 524.53 |
| All therms over the first block per month at | $ 0.1866 | $ 0.6736 | $ 0.0187 | $ 0.8789 | $ 0.0854 | $ 0.5411 | $ 0.0493 | $ 0.6758 |
| | ~~$ 0.1866~~ | ~~$ 0.7463~~ | ~~$ 0.0493~~ | ~~$ 0.9822~~ | | | | |
| **Commercial/Industrial - G-51** | | | | | | | | |
| Customer Charge per Month per Meter | $ 40.74 | | | $ 40.74 | $ 40.74 | | | $ 40.74 |
| Size of the first block | 100 therms | | | | 100 therms | | | |
| Therms in the first block per month at | $ 0.1740 | $ 0.6671 | $ 0.0187 | $ 0.8598 | $ 0.1740 | $ 0.5388 | $ 0.0493 | $ 0.7621 |
| | ~~$ 0.1740~~ | ~~$ 0.7445~~ | ~~$ 0.0493~~ | ~~$ 0.9678~~ | | | | |
| All therms over the first block per month at | $ 0.1123 | $ 0.6671 | $ 0.0187 | $ 0.7981 | $ 0.1123 | $ 0.5388 | $ 0.0493 | $ 0.7004 |
| | ~~$ 0.1123~~ | ~~$ 0.7445~~ | ~~$ 0.0493~~ | ~~$ 0.9061~~ | | | | |
| **Commercial/Industrial - G-52** | | | | | | | | |
| Customer Charge per Month per Meter | $ 122.22 | | | $ 122.22 | $ 122.22 | | | $ 122.22 |
| Size of the first block | 1000 therms | | | | 1000 therms | | | |
| Therms in the first block per month at | $ 0.1683 | $ 0.6671 | $ 0.0187 | $ 0.8541 | $ 0.1236 | $ 0.5388 | $ 0.0493 | $ 0.7117 |
| | ~~$ 0.1683~~ | ~~$ 0.7445~~ | ~~$ 0.0493~~ | ~~$ 0.9621~~ | | | | |
| All therms over the first block per month at | $ 0.1142 | $ 0.6671 | $ 0.0187 | $ 0.8000 | $ 0.0712 | $ 0.5388 | $ 0.0493 | $ 0.6593 |
| | ~~$ 0.1142~~ | ~~$ 0.7445~~ | ~~$ 0.0493~~ | ~~$ 0.9080~~ | | | | |
| **Commercial/Industrial - G-53** | | | | | | | | |
| Customer Charge per Month per Meter | $ 539.80 | | | $ 539.80 | $ 539.80 | | | $ 539.80 |
| All therms over the first block per month at | $ 0.1201 | $ 0.6671 | $ 0.0187 | $ 0.8059 | $ 0.0574 | $ 0.5388 | $ 0.0493 | $ 0.6455 |
| | ~~$ 0.1201~~ | ~~$ 0.7445~~ | ~~$ 0.0493~~ | ~~$ 0.9139~~ | | | | |
| **Commercial/Industrial - G-54** | | | | | | | | |
| Customer Charge per Month per Meter | $ 539.80 | | | $ 539.80 | $ 539.80 | | | $ 539.80 |
| All therms over the first block per month at | $ 0.0415 | $ 0.6671 | $ 0.0187 | $ 0.7273 | $ 0.0224 | $ 0.5388 | $ 0.0493 | $ 0.6105 |
| | ~~$ 0.0415~~ | ~~$ 0.7445~~ | ~~$ 0.0493~~ | ~~$ 0.8353~~ | | | | |

**Anticipated Cost of Gas**
**PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2012 THROUGH APRIL 30, 2013**
**~~PERIOD COVERED: SUMMER PERIOD, MAY 1, 2012 THROUGH OCTOBER 31, 2012~~**
**(REFER TO TEXT ON IN SECTION 16 COST OF GAS CLAUSE)**

| (Col 1) | ~~(Col 2)~~ | ~~(Col 3)~~ | (Col 2) | (Col 3) |
|---|---|---|---|---|
| **ANTICIPATED DIRECT COST OF GAS** | | | | |
| **Purchased Gas:** | | | | |
| Demand Costs: | ~~$ 4,129,301~~ | | $ 9,446,057 | |
| Supply Costs: | ~~$ 7,229,926~~ | | 26,630,667 | |
| **Storage Gas:** | | | | |
| Demand, Capacity: | ~~-~~ | | 1,092,898 | |
| Commodity Costs: | ~~-~~ | | 9,121,704 | |
| **Produced Gas:** | ~~42,000~~ | | 291,366 | |
| **Hedged Contract Savings** | ~~435,532~~ | | 1,941,641 | |
| **Hedge Underground Storage Contract (Savings)/Loss** | ~~-~~ | | - | |
| **Unadjusted Anticipated Cost of Gas** | | ~~$ 11,836,759~~ | | $ 48,524,333 |
| **Adjustments:** | | | | |
| Prior Period (Over)/Under Recovery (as of ~~May 1, 2011~~ October 31, 2011) | ~~$ (412,104)~~ | | $ 1,606,569 | |
| Interest | ~~(5,809)~~ | | 73,865 | |
| Prior Period Adjustments | ~~-~~ | | - | |
| Broker Revenues | ~~-~~ | | (396,197) | |
| Refunds from Suppliers | ~~(742,917)~~ | | - | |
| Fuel Financing | ~~-~~ | | 109,724 | |
| Transportation CGA Revenues | ~~-~~ | | (8,224) | |
| Interruptible Sales Margin | ~~-~~ | | - | |
| Capacity Release and Off System Sales Margin | ~~-~~ | | (1,130,619) | |
| Hedging Costs | ~~-~~ | | - | |
| Fixed Price Option Administrative Costs | ~~-~~ | | 40,691 | |
| **Total Adjustments** | | ~~(1,160,830)~~ | | 295,808 |
| **Total Anticipated Direct Cost of Gas** | | ~~$ 10,675,929~~ | | $ 48,820,141 |
| **Anticipated Indirect Cost of Gas** | | | | |
| **Working Capital:** | | | | |
| Total anticipated Direct Cost of Gas ~~(05/01/2011 - 10/31/2011)~~(11/01/11 - 04/30/12) | ~~$ 11,836,759~~ | | $ 48,524,333 | |
| Working Capital Rate | ~~0.0391~~ | | 0.0391 | |
| Prime Rate | ~~3.25%~~ | | 3.25% | |
| Working Capital Percentage | ~~0.127%~~ | | 0.127% | |
| Working Capital | ~~15,043~~ | | $ 61,669 | |
| Plus: Working Capital Reconciliation ~~(Acct 142.20)~~ (Acct 142.40) | ~~(1,055)~~ | | (541) | |
| Total Working Capital Allowance | | ~~$ 13,988~~ | | $ 61,128 |
| **Bad Debt:** | | | | |
| Total anticipated Direct Cost of Gas ~~(05/01/2011 - 10/31/2011)~~(11/01/11 - 04/30/12) | ~~$ 11,836,759~~ | | $ 48,524,333 | |
| Less: Refunds | - | | - | |
| Plus: Total Working Capital | ~~13,988~~ | | 61,128 | |
| Plus: Prior Period (Over)/Under Recovery | ~~(412,104)~~ | | 1,606,569 | |
| Subtotal | ~~$ 11,438,643~~ | | $ 50,192,030 | |
| Bad Debt Percentage | ~~2.37%~~ | | 2.50% | |
| Bad Debt Allowance | ~~271,096~~ | | $ 1,254,801 | |
| Plus: Bad Debt Reconciliation ~~(Acct 175.52)~~ (Acct 175.54) | ~~-~~ | | 113,348 | |
| Total Bad Debt Allowance | | ~~271,096~~ | | 1,368,148 |
| Production and Storage Capacity | | ~~-~~ | | 1,980,428 |
| Miscellaneous Overhead ~~(05/01/2011 - 10/31/2011)~~ (11/01/11 - 04/30/12) | ~~$ 13,170~~ | | $ 13,170 | |
| Times Summer ~~Winter~~ Sales | ~~22,654~~ | | 77,826 | |
| Divided by Total Sales | ~~105,301~~ | | 95,484 | |
| Miscellaneous Overhead | | ~~2,833~~ | | 10,735 |
| Total Anticipated Indirect Cost of Gas | | ~~$ 287,917~~ | | $ 3,420,439 |
| **Total Cost of Gas** | | ~~$ 10,963,846~~ | | $ 52,240,580 |

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**PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2012 THROUGH APRIL 30, 2013**
**~~PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2012 THROUGH APRIL 30, 2013~~**
**(Refer to Text in Section 16 Cost of Gas Clause)**

| (Col 1) | ~~(Col 2)~~ | ~~(Col 3)~~ | (Col 2) | (Col 3) | |
|---|---|---|---|---|---|
| Total Anticipated Direct Cost of Gas | ~~$ 10,675,929~~ | | $ 48,820,141 | | |
| Projected Prorated Sales (05/01/12 - 10/31/2012) ~~(11/01/11 - 04/30/12)~~ | ~~21,419,124~~ | | 77,755,617 | | |
| **Direct Cost of Gas Rate** | | ~~0.4984~~ | | $ 0.6279 | per therm |
| **Demand Cost of Gas Rate** | ~~$ 4,129,301~~ | ~~0.1928~~ | $ 10,538,954 | $ 0.1355 | |
| **Commodity Cost of Gas Rate** | ~~7,707,458~~ | ~~0.3598~~ | 37,985,379 | $ 0.4885 | |
| **Adjustment Cost of Gas Rate** | ~~(1,160,830)~~ | ~~(0.0542)~~ | 295,808 | $ 0.0038 | |
| **Total Direct Cost of Gas Rate** | ~~$ 10,675,929~~ | ~~0.4984~~ | $ 48,820,141 | $ 0.6279 | |
| Total Anticipated Indirect Cost of Gas | ~~$ 287,917~~ | | $ 3,420,439 | | |
| Projected Prorated Sales (05/01/12 - 10/31/2012) ~~(11/01/11 - 04/30/12)~~ | ~~21,419,124~~ | | 77,755,617 | | |
| **Indirect Cost of Gas** | | ~~$ 0.0134~~ | | $ 0.0440 | per therm |
| **TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 11/01/12** | | | | $ 0.6719 | per Therm |
| **~~TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 11/01/11~~** | | ~~$ 0.5118~~ | | | |

| | | | | |
|---|---|---|---|---|
| **RESIDENTIAL COST OF GAS RATE - 11/01/12** | | **COGwr** | **$ 0.6719** | **/therm** |
| **~~RESIDENTIAL COST OF GAS RATE - 05/01/13~~** | | **~~COGsr~~** | **~~$ 0.5118~~** | **~~/therm~~** |
| ~~Change in rate due to change in under/over recovery~~ | | | ~~$ (0.0377)~~ | ~~per therm~~ |
| **~~RESIDENTIAL COST OF GAS RATE - 06/01/2012~~** | | **~~COGsr~~** | **~~$ 0.4741~~** | **~~/therm~~** |
| ~~Change in rate due to change in under/over recovery~~ | | | ~~$ (0.0046)~~ | ~~per therm~~ |
| **~~RESIDENTIAL COST OF GAS RATE - 07/01/2012~~** | | **~~COGsr~~** | **~~$ 0.4695~~** | **~~/therm~~** |
| ~~Change in rate due to change in under/over recovery~~ | | | ~~$ 0.0515~~ | ~~per therm~~ |
| **~~RESIDENTIAL COST OF GAS RATE - 08/01/2012~~** | | **~~COGsr~~** | **~~$ 0.5210~~** | **~~/therm~~** |
| ~~Change in rate due to change in under/over recovery~~ | | | ~~$ 0.0193~~ | ~~per therm~~ |
| **~~RESIDENTIAL COST OF GAS RATE - 09/01/2012~~** | | **~~COGsr~~** | **~~$ 0.5403~~** | **~~/therm~~** |
| | Maximum | (COG + 25%) | ~~$ 0.6398~~ | $ 0.8399 |

| | | | | |
|---|---|---|---|---|
| **COM/IND LOW WINTER USE COST OF GAS RATE - 11/01/12** | | **COGwl** | **$ 0.6671** | **/therm** |
| **~~COM/IND LOW WINTER USE COST OF GAS RATE - 05/01/13~~** | | **~~COGsl~~** | **~~$ 0.5103~~** | **~~/therm~~** |
| ~~Change in rate due to change in under/over recovery~~ | | | ~~$ (0.0377)~~ | ~~/therm~~ |
| **~~COM/IND LOW WINTER USE COST OF GAS RATE - 06/01/2012~~** | | **~~COGsl~~** | **~~$ 0.4726~~** | **~~/therm~~** |
| ~~Change in rate due to change in under/over recovery~~ | | | ~~$ (0.0046)~~ | ~~/therm~~ |
| **~~COM/IND LOW WINTER USE COST OF GAS RATE - 07/01/2012~~** | | **~~COGsl~~** | **~~$ 0.4680~~** | **~~/therm~~** |
| ~~Change in rate due to change in under/over recovery~~ | | | ~~$ 0.0515~~ | ~~/therm~~ |
| **~~COM/IND LOW WINTER USE COST OF GAS RATE - 08/01/2012~~** | | **~~COGsl~~** | **~~$ 0.5195~~** | **~~/therm~~** |
| ~~Change in rate due to change in under/over recovery~~ | | | ~~$ 0.0193~~ | ~~/therm~~ |
| **~~COM/IND LOW WINTER USE COST OF GAS RATE - 09/01/2012~~** | | **~~COGsl~~** | **~~$ 0.5388~~** | **~~/therm~~** |

| | | | | | | |
|---|---|---|---|---|---|---|
| Average Demand Cost of Gas Rate Effective ~~11/01/11~~ 05/01/2012 | ~~$ 0.1928~~ | $ 0.1355 | Maximum | (COG + 25%) | ~~$ 0.6379~~ | $ 0.8339 |
| Times: Low Winter Use Ratio (Winter) | ~~0.9895~~ | 0.9585 | | | | |
| Times: Correction Factor | ~~1.0026~~ | 1.0068 | | | | |
| Adjusted Demand Cost of Gas Rate | ~~$ 0.1913~~ | $ 0.1308 | | | | |
| Commodity Cost of Gas Rate | ~~$ 0.3598~~ | $ 0.4885 | | | | |
| Adjustment Cost of Gas Rate | ~~(0.0542)~~ | 0.0038 | | | | |
| Indirect Cost of Gas Rate | ~~0.0134~~ | 0.0440 | | | | |
| Adjusted Com/Ind Low Winter Use Cost of Gas Rate | ~~$ 0.5103~~ | $ 0.6671 | | | | |

| | | | | |
|---|---|---|---|---|
| **COM/IND HIGH WINTER USE COST OF GAS RATE - 11/01/12** | | **COGwh** | **$ 0.6736** | **/therm** |
| **~~COM/IND HIGH WINTER USE COST OF GAS RATE - 05/01/13~~** | | **~~COGsh~~** | **~~$ 0.5126~~** | **~~/therm~~** |
| ~~Change in rate due to change in under/over recovery~~ | | | ~~$ (0.0377)~~ | ~~/therm~~ |
| **~~COM/IND HIGH WINTER USE COST OF GAS RATE - 06/01/2012~~** | | **~~COGsh~~** | **~~$ 0.4749~~** | **~~/therm~~** |
| ~~Change in rate due to change in under/over recovery~~ | | | ~~$ (0.0046)~~ | ~~/therm~~ |
| **~~COM/IND HIGH WINTER USE COST OF GAS RATE - 07/01/2012~~** | | **~~COGsh~~** | **~~$ 0.4703~~** | **~~/therm~~** |
| ~~Change in rate due to change in under/over recovery~~ | | | ~~$ 0.0515~~ | ~~/therm~~ |
| **~~COM/IND HIGH WINTER USE COST OF GAS RATE - 08/01/2012~~** | | **~~COGsh~~** | **~~$ 0.5218~~** | **~~/therm~~** |
| ~~Change in rate due to change in under/over recovery~~ | | | ~~$ 0.0193~~ | ~~/therm~~ |
| **~~COM/IND HIGH WINTER USE COST OF GAS RATE - 09/01/2012~~** | | **~~COGsh~~** | **~~$ 0.5411~~** | **~~/therm~~** |

| | | | | | | |
|---|---|---|---|---|---|---|
| Average Demand Cost of Gas Rate Effective 11/01/11 05/01/2012 | ~~$ 0.1928~~ | $ 0.1355 | Maximum | (COG + 25%) | ~~$ 0.6408~~ | $ 0.8420 |
| Times: High Winter Use Ratio (Winter) | ~~1.0014~~ | 1.0068 | | | | |
| Times: Correction Factor | ~~1.0026~~ | 1.0068 | | | | |
| Adjusted Demand Cost of Gas Rate | ~~$ 0.1936~~ | $ 0.1373 | | | | |
| Commodity Cost of Gas Rate | ~~$ 0.3598~~ | $ 0.4885 | Minimum | | | |
| Adjustment Cost of Gas Rate | ~~(0.0542)~~ | 0.0038 | Maximum | | | |
| Indirect Cost of Gas Rate | ~~0.0134~~ | 0.0440 | | | | |
| Adjusted Com/Ind High Winter Use Cost of Gas Rate | ~~$ 0.5126~~ | $ 0.6736 | | | | |

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**II. RATE SCHEDULES**
**CALCULATION OF FIXED WINTER PERIOD COST OF GAS RATE**
**PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2012 THROUGH APRIL 30, 2013**
**~~PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2011 THROUGH APRIL 30, 2012~~**
**(Refer to Text in Section 17(A) Fixed Price Option Program)**

| (Col 1) | (Col 2) | (Col 3) | (Col 2) | (Col 3) |
|---|---|---|---|---|
| Total Anticipated Direct Cost of Gas | ~~$ 61,876,339~~ | | $ 48,820,141 | |
| Projected Prorated Sales ~~(11/01/2011 - 4/30/2012)~~ (11/01/2012 - 4/30/2013) | ~~82,632,661~~ | | 77,755,617 | |
| **Direct Cost of Gas Rate** | | ~~$ 0.7488~~ | | $ 0.6279 per therm |
| **Demand Cost of Gas Rate** | ~~$ 12,917,335~~ | ~~$ 0.1563~~ | $ 10,538,954 | $ 0.1355 |
| **Commodity Cost of Gas Rate** | ~~46,765,733~~ | ~~$ 0.5659~~ | $ 37,985,379 | $ 0.4885 |
| **Adjustment Cost of Gas Rate** | ~~2,193,271~~ | ~~$ 0.0265~~ | $ 295,808 | $ 0.0038 |
| **Total Direct Cost of Gas Rate** | ~~$ 61,876,339~~ | ~~$ 0.7488~~ | $ 48,820,141 | $ 0.6279 |
| Total Anticipated Indirect Cost of Gas | ~~$ 3,616,575~~ | | $ 3,420,439 | |
| Projected Prorated Sales ~~(11/01/2011 - 4/30/2012)~~ (11/01/2012 - 4/30/2013) | ~~82,632,661~~ | | 77,755,617 | |
| **Indirect Cost of Gas** | | ~~$ 0.0438~~ | | $ 0.0440 per therm |
| **TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE NOVEMBER 1, 2011 ~~2010~~** | | **~~$ 0.7926~~** | | **$ 0.6719** |
| **FPO Risk Premium** | | ~~$ 0.0200~~ | | $ 0.0200 |
| **TOTAL PERIOD FIXED PRICE OPTION COST OF GAS RATE EFFECTIVE NOVEMBER 1, 2011 ~~2010~~** | | **~~$ 0.8126~~** | | **$ 0.6919** |

| | | | | |
|---|---|---|---|---|
| **RESIDENTIAL COST OF GAS RATE - 11/01/12** | | | **COGwr** | **$ 0.6919 /therm** |
| **~~RESIDENTIAL COST OF GAS RATE -11/01/2011~~** | **~~COGwr~~** | **~~$ 0.8126~~** | **~~/therm~~** | |

| | | | | |
|---|---|---|---|---|
| **COM/IND LOW WINTER USE COST OF GAS RATE - 11/01/12** | | | **COGwl** | **$ 0.6871 /therm** |
| **~~COM/IND LOW WINTER USE COST OF GAS RATE - 11/01/2011~~** | **~~COGwr~~** | **~~$ 0.8111~~** | **~~/therm~~** | |

| | | |
|---|---|---|
| Average Cost of Gas Rate Effective ~~11/01/2011~~ 11/01/2012 | ~~$ 0.1563~~ | $ 0.1355 |
| Times: Low Winter Use Ratio (Winter) | ~~$ 0.9895~~ | $ 0.9585 |
| Times: Correction Factor | ~~$ 1.0014~~ | $ 1.0068 |
| Adjusted Demand Cost of Gas Rate | ~~$ 0.1549~~ | $ 0.1308 |
| Commodity Cost of Gas Rate | ~~$ 0.5659~~ | $ 0.4885 |
| Adjustment Cost of Gas Rate | ~~$ 0.0265~~ | $ 0.0038 |
| Indirect Cost of Gas Rate | ~~$ 0.0438~~ | $ 0.0440 |
| Adjusted Com/Ind Low Winter Use Cost of Gas Rate | ~~$ 0.7911~~ | $ 0.6671 |
| FPO Risk Premium | ~~$ 0.0200~~ | $ 0.0200 |
| | ~~$ 0.8111~~ | $ 0.6871 |

| | | | | |
|---|---|---|---|---|
| **COM/IND HIGH WINTER USE COST OF GAS RATE -11/01/12** | | | **COGwh** | **$ 0.6936 /therm** |
| **~~COM/IND HIGH WINTER USE COST OF GAS RATE - 11/01/2011~~** | **~~COGwr~~** | **~~$ 0.8129~~** | **~~/therm~~** | |

| | | |
|---|---|---|
| Average Cost of Gas Rate Effective ~~11/01/2011~~ 11/01/2012 | ~~$ 0.1563~~ | $ 0.1355 |
| Times: High Winter Use Ratio (Winter) | ~~$ 1.0014~~ | $ 1.0068 |
| Times: Correction Factor | ~~$ 1.0014~~ | $ 1.0068 |
| Adjusted Demand Cost of Gas Rate | ~~$ 0.1567~~ | $ 0.1373 |
| Commodity Cost of Gas Rate | ~~$ 0.5659~~ | $ 0.4885 |
| Adjustment Cost of Gas Rate | ~~$ 0.0265~~ | $ 0.0038 |
| Indirect Cost of Gas Rate | ~~$ 0.0438~~ | $ 0.0440 |
| Adjusted Com/Ind Low Winter Use Cost of Gas Rate | ~~$ 0.7929~~ | $ 0.6736 |
| FPO Risk Premium | ~~$ 0.0200~~ | $ 0.0200 |
| | ~~$ 0.8129~~ | $ 0.6936 |

| (Col 1) | ~~(Col 2)~~ | ~~(Col 3)~~ | ~~(Col 4)~~ | (Col 2) | (Col 3) | (Col 4) |
|---|---|---|---|---|---|---|
| ANTICIPATED COST OF SUPPLEMENTAL GAS SUPPLIES: | | | | | | |
| PROPANE | ~~$ -~~ | | | $ - | | |
| LNG | ~~$ 381,653~~ | | | 291,366 | | |
| TOTAL ANTICIPATED COST OF SUPPLEMENTAL GAS SUPPLIES | ~~381,653~~ | | | 291,366 | | |
| ESTIMATED PERCENTAGE USED FOR PRESSURE SUPPORT PURPOSES | ~~9.9%~~ | | | 9.9% | | |
| ESTIMATED COST OF LIQUIDS USED FOR PRESSURE SUPPORT PURPOSES | ~~$ 37,784~~ | | | $ 28,845 | | |
| PROJECTED FIRM THROUGHPUT (THERMS): | | | | | | |
| FIRM SALES | ~~82,647,332~~ | ~~69.1%~~ | | 77,826,455 | 65.4% | |
| FIRM TRANSPORTATION SUBJECT TO FTCG | ~~36,930,101~~ | ~~30.9%~~ | | 41,120,858 | 34.6% | |
| TOTAL FIRM THROUGHPUT SUBJECT TO COST OF GAS CHARGE | ~~119,577,433~~ | ~~100.0%~~ | | 118,947,312 | 100.0% | |
| TRANSPORTATION SHARE OF SUPPLEMENTAL GAS SUPPLIES | ~~30.9%~~ | ~~37,784~~ | = ~~$ 11,669~~ | 34.6% x $ 28,845 | | = $ 9,972 |
| PRIOR (OVER) OR UNDER COLLECTION | | | ~~(10,838)~~ | | | (1,888) |
| NET AMOUNT TO COLLECT FROM (RETURNED TO) TRANSPORTATION CUSTOMERS | | | ~~$ 831~~ | | | $ 8,084 |
| PROJECTED FIRM TRANSPORTATION THROUGHPUT | | | ~~36,930,101~~ | | | 41,120,858 |
| FIRM TRANSPORTATION COST OF GAS ADJUSTMENT | | | ~~$0.0000~~ | | | $0.0002 |

**Manfactured Gas Plants**

| | | | |
|---|---|---|---|
| Required annual increase in rates | ~~$56,582~~ | $256,547 | |
| DG 10-17 Base Rate Revision Collections | ~~-$78,892~~ | -$78,892 | |
| Environmental Subtotal | ~~-$22,310~~ | $177,655 | |
| Overall Annual Net Increase to Rates | ~~$0~~ | $177,655 | |
| Estimated weather normalized firm therms billed for the twelve months ended 10/31/13 ~~10/31/12~~ - sales and transportation | ~~-163,588,592~~ | 158,062,349 | therms |
| Surcharge per therm | ~~$0.0000~~ | $0.0011 | per therm |
| **Total Environmental Surcharge** | ~~$0.0000~~ | $0.0011 | |

## Rate Case Expense/Temporary Rate Reconciliation (RDE) Factor Calculation

### Rate Case Expense Factors for Resdential Customers

| | | | |
|---|---|---|---|
| Rate Case Expense | $ | 623,004 | ~~$ 1,112,811~~ |
| Temporary Rate Reconciliation - DG 10-017 | $ | - | ~~1,130,418~~ |
| Sipulation per Settlement Argument - DG 10-017 | | - | ~~(7,776)~~ |
| Reconciliation DG 08-009 and Merger Incentive DG 06-707 | | - | ~~(143,593.0)~~ |
| Total Rate Case Expense/Temporary Rate Reconciliation Recoverable | $ | 623,004 | ~~$ 2,091,860~~ |
| OffPeak 2011 Rate Case Expense Factor | | 0.011612706 | ~~0.0052~~ |
| OffPeak 2011 Projected Volumes | | 16,967,216 | ~~36,952,643~~ |
| OffPeak 2011 Rate Case Expense Collection | | 197,035 | ~~192,154~~ |
| Total Net Rate Case Expense/Temporary Rate Reconciliation Recoverable | | 425,969 | ~~1,899,706~~ |
| Forecasted Annual Throughput Volumes for Residential Customer (A:VOLres) | | 57,541,620 | ~~61,976,058~~ |
| Forecasted Annual Throughput Volumes for Commercial/Industrial Customer (A:VOLc&i) | | 100,520,729 | ~~101,612,535~~ |
| Total Volumes | | 158,062,349 | ~~163,588,592~~ |
| **Rate Case Expense Factor** | $ | 0.0027 | ~~$ 0.0116~~ |

**Local Distribution Adjustment Charge Calculation**

| | | | | Sales Customers | Transporatation Customers | | |
|---|---|---|---|---|---|---|---|
| **Residential Non Heating Rates - R-1** | | | | | | | |
| Energy Efficiency Charge | ~~$0.0498~~ | | $0.0147 | | | | |
| Demand Side Management Charge | ~~0.0000~~ | | 0.0000 | | | | |
| Conservation Charge (CCx) | | ~~$0.0498~~ | | $0.0147 | | | |
| Relief Holder and pond at Gas Street, Concord, NH | ~~0.0000~~ | | 0.0000 | | | | |
| Manufactured Gas Plants | ~~0.0000~~ | | 0.0011 | | | | |
| Environmental Surcharge (ES) | | ~~0.0000~~ | | 0.0011 | | | |
| Interruptible Transportation Margin Credit (ITMC) | | ~~0.0000~~ | | 0.0000 | | | |
| Cost Allowance Adjustment Factor | | ~~(0.0013)~~ | | 0.0000 | | | |
| Rate Case Expense Factor (RCEF) | | ~~0.0116~~ | | 0.0027 | | | |
| Residential Low Income Assistance Program (RLIAP) | | ~~0.0092~~ | | 0.0073 | | | |
| **LDAC** | | **~~$0.0693~~** | | **$0.0258** | | | **per therm** |
| **Residential Heating Rates - R-3, R-4** | | | | | | | |
| Energy Efficiency Charge | ~~$0.0498~~ | | $0.0147 | | | | |
| Demand Side Management Charge | ~~0.0000~~ | | 0.0000 | | | | |
| Conservation Charge (CCx) | | ~~$0.0498~~ | | $0.0147 | | | |
| Relief Holder and pond at Gas Street, Concord, NH | ~~0.0000~~ | | 0.0000 | | | | |
| Manufactured Gas Plants | ~~0.0000~~ | | 0.0011 | | | | |
| Environmental Surcharge (ES) | | ~~0.0000~~ | | 0.0011 | | | |
| Cost Allowance Adjustment Factor | | ~~(0.0013)~~ | | 0.0000 | | | |
| Rate Case Expense Factor (RCEF) | | ~~0.0116~~ | | 0.0027 | | | |
| Residential Low Income Assistance Program (RLIAP) | | ~~0.0092~~ | | 0.0073 | | | |
| **LDAC** | | **~~$0.0693~~** | | **$0.0258** | | | **per therm** |
| **Commercial/Industrial Low Annual Use Rates - G-41, G-51** | | | | | | | |
| Energy Efficiency Charge | ~~$0.0298~~ | | $0.0076 | | | | |
| Demand Side Management Charge | ~~0.0000~~ | | 0.0000 | | | | |
| Conservation Charge (CCx) | | ~~$0.0298~~ | | $0.0076 | ~~$0.0298~~ | $0.0076 | |
| Relief Holder and pond at Gas Street, Concord, NH | ~~0.0000~~ | | 0.0000 | | | | |
| Manufactured Gas Plants | ~~0.0000~~ | | 0.0011 | | | | |
| Environmental Surcharge (ES) | | ~~0.0000~~ | | 0.0011 | ~~0.0000~~ | 0.0011 | |
| Cost Allowance Adjustment Factor | | ~~(0.0013)~~ | | 0.0000 | ~~0.0023~~ | 0.0000 | |
| Gas Restructuring Expense Factor (GREF) | | ~~0.0000~~ | | 0.0000 | ~~0.0000~~ | 0.0000 | |
| Rate Case Expense Factor (RCEF) | | ~~0.0116~~ | | 0.0027 | ~~0.0116~~ | 0.0027 | |
| Residential Low Income Assistance Program (RLIAP) | | ~~0.0092~~ | | 0.0073 | ~~0.0092~~ | 0.0073 | |
| **LDAC** | | **~~$0.0493~~** | | **$0.0187** | **~~$0.0529~~** | **$0.0187** | **per therm** |
| **Commercial/Industrial Medium Annual Use Rates - G-42, G-52** | | | | | | | |
| Energy Efficiency Charge | ~~$0.0298~~ | | $0.0076 | | | | |
| Demand Side Management Charge | ~~0.0000~~ | | 0.0000 | | | | |
| Conservation Charge (CCx) | | ~~$0.0298~~ | | $0.0076 | ~~$0.0298~~ | $0.0076 | |
| Relief Holder and pond at Gas Street, Concord, NH | ~~0.0000~~ | | 0.0000 | | | | |
| Manufactured Gas Plants | ~~0.0000~~ | | 0.0011 | | | | |
| Environmental Surcharge (ES) | | ~~0.0000~~ | | 0.0011 | ~~0.0000~~ | 0.0011 | |
| Cost Allowance Adjustment Factor | | ~~(0.0013)~~ | | 0.0000 | ~~0.0023~~ | 0.0000 | |
| Gas Restructuring Expense Factor (GREF) | | ~~0.0000~~ | | 0.0000 | ~~0.0000~~ | 0.0000 | |
| Rate Case Expense Factor (RCEF) | | ~~0.0116~~ | | 0.0027 | ~~0.0116~~ | 0.0027 | |
| Residential Low Income Assistance Program (RLIAP) | | ~~0.0092~~ | | 0.0073 | ~~0.0092~~ | 0.0073 | |
| **LDAC** | | **~~$0.0493~~** | | **$0.0187** | **~~$0.0529~~** | **$0.0187** | **per therm** |
| **Commercial/Industrial Large Annual Use Rates - G-43, G-53, G-54** | | | | | | | |
| Energy Efficiency Charge | ~~$0.0298~~ | | $0.0076 | | | | |
| Demand Side Management Charge | ~~0.0000~~ | | 0.0000 | | | | |
| Conservation Charge (CCx) | | ~~$0.0298~~ | | $0.0076 | ~~$0.0298~~ | $0.0076 | |
| Relief Holder and pond at Gas Street, Concord, NH | ~~0.0000~~ | | 0.0000 | | | | |
| Manufactured Gas Plants | ~~0.0000~~ | | 0.0011 | | | | |
| Environmental Surcharge (ES) | | ~~0.0000~~ | | 0.0011 | ~~0.0000~~ | 0.0011 | |
| Cost Allowance Adjustment Factor | | ~~(0.0013)~~ | | 0.0000 | ~~0.0023~~ | 0.0000 | |
| Gas Restructuring Expense Factor (GREF) | | ~~0.0000~~ | | 0.0000 | ~~0.0000~~ | 0.0000 | |
| Rate Case Expense Factor (RCEF) | | ~~0.0116~~ | | 0.0027 | ~~0.0116~~ | 0.0027 | |
| Residential Low Income Assistance Program (RLIAP) | | ~~0.0092~~ | | 0.0073 | ~~0.0092~~ | 0.0073 | |
| **LDAC** | | **~~$0.0493~~** | | **$0.0187** | **~~$0.0529~~** | **$0.0187** | **per therm** |

Issued: August 31, 2012
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Issued: By_____
Victor D. Del Vecchio
Title: President

ATTACHMENT B
Schedule of Administrative Fees and Charges

| | | | |
|---|---|---|---|
| I. | Supplier Balancing Charge: | ~~$0.22~~ | $0.19 per MMBtu of Daily Imbalance Volumes |
| II. | Capacity Mitigation Fee | ~~15%~~ | 15% of the Proceeds from the Marketing of Capacity for Mitigation. |
| III. | Peaking Demand Charge | ~~$18.96~~ | $18.62 MMBTU of Peak MDQ. |

IV. Company Allowance Calculation (per Schedule 25)

| | | | |
|---|---|---|---|
| | ~~157,306,800~~ | 138,409,150 | Total Sendout - Therms Jul-2011 - Jun-2012 |
| | ~~155,168,138~~ | 136,259,218 | Total Throughput - Therms Jul-2011 - Jun-2012 |
| | ~~2,138,662~~ | 2,149,932 | Variance (Sendout - Throughput) |
| Company Allowance Percentage 2012-13 | ~~1.4%~~ | 1.6% | Variance / Total Sendout |

ATTACHMENT C

**CAPACITY ALLOCATORS**

| Rate Class | | Pipeline | Storage | Peaking | Total |
|---|---|---|---|---|---|
| G-41 | Low Annual /High Winter Use | ~~38%~~ 38.0% | ~~21%~~ 21.0% | ~~41%~~ 41.0% | 100.0% |
| G-51 | Low Annual /Low Winter Use | ~~52%~~ 49.0% | ~~16%~~ 17.0% | ~~32%~~ 34.0% | 100.0% |
| G-42 | Medium Annual / High Winter | ~~38%~~ 38.0% | ~~21%~~ 21.0% | ~~41%~~ 41.0% | 100.0% |
| G-52 | High Annual / Low Winter Use | ~~52%~~ 49.0% | ~~16%~~ 17.0% | ~~32%~~ 34.0% | 100.0% |
| G-43 | High Annual / High Winter | ~~38%~~ 38.0% | ~~21%~~ 21.0% | ~~41%~~ 41.0% | 100.0% |
| G-53 | High Annual / Load Factor < 90% | ~~52%~~ 49.0% | ~~16%~~ 17.0% | ~~32%~~ 34.0% | 100.0% |
| G-54 | High Annual / Load Factor > 90% | ~~52%~~ 49.0% | ~~16%~~ 17.0% | ~~32%~~ 34.0% | 100.0% |

**ENERGY NORTH NATURAL GAS, INC.**

**Peak 2012 - 2013 Winter Cost of Gas Filing**

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**ENERGY NORTH NATURAL GAS, INC.**

**Peak 2012 - 2013 Winter Cost of Gas Filing**
**Summary**

| | (a) | Reference (b) | | PK 12-13 Nov - Apr (c) |
|---|---|---|---|---|
| **Anticipated Direct Cost of Gas** | | | | |
| | Purchased Gas: | | | |
| | Demand Costs: | Sch. 5A, col (j), ln 43 | $ | 9,446,057 |
| | Supply Costs | Sch. 6, col (i), ln 44 | | 26,630,667 |
| | Storage Gas: | | | |
| | Demand, Capacity: | Sch. 5A, col (k), ln 58 | $ | 1,092,898 |
| | Commodity Costs: | Sch. 6, col (i), ln 47 | | 9,121,704 |
| | Produced Gas: | Sch. 6, col (i), ln 53 | $ | 291,366 |
| | Hedge Contract (Savings)/Loss | Sch. 7, col (i), ln 34 | $ | 1,941,641 |
| | Hedge Underground Storage Contract (Savings)/Loss | Sch. 16, col (e), ln 172 | $ | - |
| | **Total Unadjusted Cost of Gas** | | $ | 48,524,333 |
| **Adjustments:** | | | | |
| | Prior Period (Over)/Under Recovery) | Sch. 3, col (c) ln 28 | $ | 1,606,569 |
| | Interest 10/31/12 - 04//30/13 | Sch. 3, col (q) ln 193 | | 73,865 |
| | Prior Period Adjustments | Sch. 4, ln 26 col (b) | | - |
| | Refunds from Suppliers | Sch. 4, ln 26 col (c) | | - |
| | Broker Revenues | Sch. 4, ln 26 col (d) | | (396,197) |
| | Fuel Financing | Sch. 4, ln 26 col (e) | | 109,724 |
| | Transportation CGA Revenues | Sch. 4, ln 26 col (f) | | (8,224) |
| | Interruptible Sales Margin | Sch. 4, ln 26 col (g) | | - |
| | Capacity Release and Off System Sales Margins | Sch. 4, ln 26 col (h) + col (i) | | (1,130,619) |
| | Hedging Costs | Sch. 4, ln 26 col (j) | | - |
| | FPO Premium - Collection | | | |
| | Fixed Price Option Administrative Costs | Sch. 4, ln 26 col (k) | | 40,691 |
| | **Total Adjustments** | | $ | 295,808 |
| **Total Anticipated Direct Costs** | | lns 23 + 40 | $ | 48,820,141 |
| **Anticipated Indirect Cost of Gas** | | | | |
| **Working Capital** | | | | |
| | Total Unadjusted Anticipated Cost of Gas | Ln 23 | $ | 48,524,333 |
| | Lead Lag Days / 365 | DG 10-017, 14.27 / 365 | | 0.0391 |
| | Prime Rate | | | 3.25% |
| | Working Capital Percentage | per GTC 16(f), ln 47 * ln 48 | | 0.127% |
| | Working Capital | ln 46 * ln 49 | | 61,669 |
| | Plus: Working Capital Reconciliation | Sch. 3, col (c), ln 78 | | (541) |
| | **Total Working Capital Allowance** | lns 50 + 51 | $ | 61,128 |
| **Bad Debt** | | | | |
| | Total Unadjusted Anticipated Cost of Gas | ln 23 | $ | 48,524,333 |
| | Less Refunds | ln 30 | | - |
| | Plus Working Capital | ln 53 | | 61,128 |
| | Plus Prior Period (Over) Under Recovery | ln 27 | | 1,606,569 |
| | Subtotal | | $ | 50,192,030 |
| | Bad Debt Percentage | per GTC 16(f) | | 2.50% |
| | Bad Debt Allowance | ln 60 * ln 61 | $ | 1,254,801 |
| | Prior Period Bad Debt Allowance | Sch. 3, col (c), ln 162 | | 113,348 |
| | **Total Bad Debt Allowance** | lns 63 + 64 | $ | 1,368,148 |
| **Production and Storage Capacity** | | per GTC16(f) | $ | 1,980,428 |
| **Miscellaneous Overhead** | | per GTC 16(f) | $ | 13,170 |
| | Sales Volume | Sch. 10B, ln 23/1000 | | 77,826 |
| | Divided by Total Sales | Sch. 10B, ln 23/1000 | | 95,484 |
| | Ratio | | | 81.51% |
| | **Miscellaneous Overhead** | lns 70 * 73 | $ | 10,735 |
| **Total Anticipated Indirect Cost of Gas** | | lns 53 + 66 + 68 + 75 | $ | 3,420,439 |
| **Total Cost of Gas** | | lns 42 + 77 | $ | 52,240,580 |
| **Projected Forecast Sales (Therms)** | | Sch. 3, col (q), ln 52 | | 77,755,617 |

**ENERGY NORTH NATURAL GAS, INC.**

**Peak 2012 - 2013 Winter Cost of Gas Filing**
**Summary of Supply and Demand Forecast**

| For Month of: | | Peak Costs May 12 - Oct 12 | Nov-12 | Dec-12 | Jan-13 | Feb-13 | Mar-13 | Apr-13 | May-13 | Peak Period Nov - Apr |
|---|---|---|---|---|---|---|---|---|---|---|
| (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) |
| **I. Gas Volumes (Therms)** | | | | | | | | | | |
| | | | | | | | | | 1,999,709 | 2.5% |
| **A. Firm Demand Volumes** | | | | | | | | | | |
| Firm Gas Sales | Sch. 10B, ln 23 | - | 2,033,163 | 11,289,618 | 16,713,541 | 17,879,201 | 15,456,597 | 10,384,290 | 3,999,207 | 77,755,617 |
| Lost Gas (Unaccounted for) | | - | 166,779 | 253,405 | 299,313 | 261,339 | 228,891 | 134,772 | | 1,344,499 |
| Company Use | | - | 81,276 | 123,491 | 145,863 | 127,357 | 111,545 | 65,678 | | 655,210 |
| Unbilled Therms | | - | 7,641,002 | 3,409,316 | 648,303 | (2,720,057) | (2,179,583) | (2,566,730) | (3,999,207) | 233,044 |
| **Total Firm Volumes** | Sch. 6, ln 92 | - | 9,922,220 | 15,075,830 | 17,807,020 | 15,547,840 | 13,617,450 | 8,018,010 | | 79,988,370 |
| **B. Supply Volumes (Therms)** | | | | | | | | | | |
| Pipeline Gas: | | | | | | | | | | |
| Dawn Supply | Sch. 6, ln 63 | - | 924,000 | 926,310 | 954,800 | 862,400 | 954,800 | 820,050 | | 5,442,360 |
| Niagara Supply | Sch. 6, ln 64 | - | 721,490 | 745,360 | 745,360 | 672,980 | 745,360 | 721,490 | | 4,352,040 |
| TGP Supply (Direct) | Sch. 6, ln 65 | - | 5,292,980 | 5,155,150 | 5,155,150 | 4,656,190 | 5,155,150 | 5,272,190 | | 30,686,810 |
| Dracut Supply 1 - Baseload | Sch. 6, ln 66 | - | - | 2,380,840 | 2,380,840 | 2,150,610 | - | - | | 6,912,290 |
| Dracut Supply 2 - Swing | Sch. 6, ln 67 | - | 3,531,220 | 957,880 | 1,983,520 | 2,142,140 | 3,002,230 | 3,362,590 | | 14,979,580 |
| City Gate Delivered Supply | Sch. 6, ln 68 | - | - | - | - | - | - | - | | - |
| LNG Truck | Sch. 6, ln 69 | - | 21,560 | 22,330 | 680,680 | - | 44,660 | - | | 769,230 |
| Propane Truck | Sch. 6, ln 70 | - | - | - | - | - | - | - | | - |
| PNGTS | Sch. 6, ln 71 | - | 58,520 | 76,230 | 83,160 | 71,610 | 66,990 | 46,970 | | 403,480 |
| Granite Ridge | Sch. 6, ln 72 | - | - | - | - | - | - | - | | - |
| Subtotal Pipeline Volumes | | - | 10,549,770 | 10,264,100 | 11,983,510 | 10,555,930 | 9,969,190 | 10,223,290 | | 63,545,790 |
| Storage Gas: | | | | | | | | | | |
| TGP Storage | Sch. 6, ln 77 | - | 1,223,530 | 4,811,730 | 5,793,480 | 4,971,120 | 3,670,590 | 52,360 | | 20,522,810 |
| Produced Gas: | | | | | | | | | | |
| LNG Vapor | Sch. 6, ln 80 | - | 21,560 | 22,330 | 710,710 | 20,790 | 22,330 | 21,560 | | 819,280 |
| Propane | Sch. 6, ln 81 | - | - | - | - | - | - | - | | - |
| Subtotal Produced Gas | | - | 21,560 | 22,330 | 710,710 | 20,790 | 22,330 | 21,560 | | 819,280 |
| Less - Gas Refill: | | | | | | | | | | |
| LNG Truck | Sch. 6, ln 86 | - | (21,560) | (22,330) | (680,680) | - | (44,660) | - | | (769,230) |
| Propane | Sch. 6, ln 87 | - | - | - | - | - | - | - | | - |
| TGP Storage Refill | Sch. 6, ln 88 | - | (1,851,080) | - | - | - | - | (2,279,200) | | (4,130,280) |
| Subtotal Refills | | - | (1,872,640) | (22,330) | (680,680) | - | (44,660) | (2,279,200) | | (4,899,510) |
| Total Firm Sendout Volumes | lns 31 + 34 + 39 + 45 | - | 9,922,220 | 15,075,830 | 17,807,020 | 15,547,840 | 13,617,450 | 8,018,010 | | 79,988,370 |

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**ENERGY NORTH NATURAL GAS, INC.**

**Peak 2012 - 2013 Winter Cost of Gas Filing**
**Summary of Supply and Demand Forecast**

| For Month of: | | Peak Costs May 12 - Oct 12 | Nov-12 | Dec-12 | Jan-13 | Feb-13 | Mar-13 | Apr-13 | May-13 | Peak Period Nov - Apr |
|---|---|---|---|---|---|---|---|---|---|---|
| **II. Gas Costs** | | | | | | | | | | |
| **A. Demand Costs** | | | | | | | | | | |
| Supply | | | | | | | | | | |
| Niagra Supply | Sch.5A, ln 12 | [redacted] | | | | | | | | |
| Subtotal Supply Demand | | | | | | | | | | |
| Less Capacity Credit | | | | | | | | | | |
| Net Pipeline Demand Costs | | | | | | | | | | |
| Pipeline: | | | | | | | | | | |
| Iroquois Gas Trans Service RTS 470-0 | Sch.5A, ln 16 | [redacted] | | | | | | | | |
| Tenn Gas Pipeline 95346 Z5-Z6 | Sch.5A, ln 17 | | | | | | | | | |
| Tenn Gas Pipeline 2302 Z5-Z6 | Sch.5A, ln 18 | | | | | | | | | |
| Tenn Gas Pipeline 8587 Z0-Z6 | Sch.5A, ln 19 | | | | | | | | | |
| Tenn Gas Pipeline 8587 Z1-Z6 | Sch.5A, ln 20 | | | | | | | | | |
| Tenn Gas Pipeline 8587 Z4-Z6 | Sch.5A, ln 21 | | | | | | | | | |
| Tenn Gas Pipeline (Dracut) 42076 Z6-Z6 | Sch.5A, ln 22 | | | | | | | | | |
| Tenn Gas Pipeline (Concord Lateral) Z6-Z6 | Sch.5A, ln 23 | | | | | | | | | |
| Portland Natural Gas Trans Service | Sch.5A, ln 24 | | | | | | | | | |
| ANE (TransCanada via Union to Iroquois) | Sch.5A, ln 25 | | | | | | | | | |
| Tenn Gas Pipeline Z4-Z6 stg 632 | Sch.5A, ln 26 | | | | | | | | | |
| Tenn Gas Pipeline Z4-Z6 stg 11234 | Sch.5A, ln 27 | | | | | | | | | |
| Tenn Gas Pipeline Z5-Z6 stg 11234 | Sch.5A, ln 28 | | | | | | | | | |
| National Fuel FST 2358 | Sch.5A, ln 29 | | | | | | | | | |
| Subtotal Pipeline Demand | | $ 1,363,979 | $ 1,071,942 | $ 1,071,942 | $ 1,071,942 | $ 1,071,942 | $ 1,071,942 | $ 1,071,942 | | $ 7,795,631 |
| Less Capacity Credit | | (349,417) | (231,914) | (231,914) | (231,914) | (231,914) | (231,914) | (231,914) | | (1,740,900) |
| Net Pipeline Demand Costs | | $ 1,014,563 | $ 840,028 | $ 840,028 | $ 840,028 | $ 840,028 | $ 840,028 | $ 840,028 | | $ 6,054,731 |
| Peaking Supply: | | | | | | | | | | |
| Tenn Gas Pipeline (Concord Lateral) Z6-Z6 | Sch.5A, ln 34 | [redacted] | | | | | | | | |
| Granite Ridge Demand | Sch.5A, ln 35 | | | | | | | | | |
| DOMAC Demand NSB041 | Sch.5A, ln 36 | | | | | | | | | |
| Subtotal Peaking Demand | | $ 2,026,707 | $ 316,420 | $ 441,170 | $ 441,170 | $ 441,170 | $ 441,170 | $ 316,420 | | $ 4,424,227 |
| Less Capacity Credit | | (519,190) | (68,457) | (95,447) | (95,447) | (95,447) | (95,447) | (68,457) | | (1,037,892) |
| Net Peaking Supply Demand Costs | | $ 1,507,517 | $ 247,963 | $ 345,723 | $ 345,723 | $ 345,723 | $ 345,723 | $ 247,963 | | $ 3,386,335 |
| Storage: | | | | | | | | | | |
| Dominion - Demand | Sch.5A, ln 46 | [redacted] | | | | | | | | |
| Dominion - Storage | Sch.5A, ln 47 | | | | | | | | | |
| Honeoye - Demand | Sch.5A, ln 48 | | | | | | | | | |
| National Fuel - Demand | Sch.5A, ln 49 | | | | | | | | | |
| National Fuel - Capacity | Sch.5A, ln 50 | | | | | | | | | |
| Tenn Gas Pipeline - Demand | Sch.5A, ln 51 | | | | | | | | | |
| Tenn Gas Pipeline - Capacity | Sch.5A, ln 52 | | | | | | | | | |
| Subtotal Storage Demand | | $ 715,492 | $ 119,249 | $ 119,249 | $ 119,249 | $ 119,249 | $ 119,249 | $ 119,249 | | $ 1,430,985 |
| Less Capacity Credit | | (183,291) | (25,799) | (25,799) | (25,799) | (25,799) | (25,799) | (25,799) | | (338,087) |
| Net Storage Demand Costs | | $ 532,202 | $ 93,449 | $ 93,449 | $ 93,449 | $ 93,449 | $ 93,449 | $ 93,449 | | $ 1,092,898 |
| Total Demand Charges | lns 54 + 73 + 81 + 93 | $ 4,106,179 | $ 1,508,666 | $ 1,633,452 | $ 1,633,452 | $ 1,633,346 | $ 1,633,452 | $ 1,508,666 | | $ 13,657,212 |
| Total Capacity Credit | lns 55 + 74 + 82 + 94 | (1,051,898) | (326,399) | (353,396) | (353,396) | (353,373) | (353,396) | (326,399) | | (3,118,258) |
| Net Demand Charges | | $ 3,054,281 | $ 1,182,267 | $ 1,280,055 | $ 1,280,055 | $ 1,279,973 | $ 1,280,055 | $ 1,182,267 | | $ 10,538,954 |

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**ENERGY NORTH NATURAL GAS, INC.**

**Peak 2012 - 2013 Winter Cost of Gas Filing**
**Summary of Supply and Demand Forecast**

| For Month of: | | Peak Costs May 12 - Oct 12 | Nov-12 | Dec-12 | Jan-13 | Feb-13 | Mar-13 | Apr-13 | May-13 | Peak Period Nov - Apr |
|---|---|---|---|---|---|---|---|---|---|---|
| **B. Commodity Costs** | | | | | | | | | | |
| Pipeline: | | | | | | | | | | |
| Dawn Supply | Sch. 6, ln 12 | | | | | | | | | |
| Niagara Supply | Sch. 6, ln 13 | | | | | | | | | |
| TGP Supply (Direct) | Sch. 6, ln 14 | | | | | | | | | |
| Dracut Supply 1 - Baseload | Sch. 6, ln 15 | | | | | | | | | |
| Dracut Supply 2 - Swing | Sch. 6, ln 16 | | | | | | | | | |
| City Gate Delivered Supply | Sch. 6, ln 17 | | | | | | | | | |
| LNG Truck | Sch. 6, ln 18 | | | | | | | | | |
| Propane Truck | Sch. 6, ln 19 | | | | | | | | | |
| PNGTS | Sch. 6, ln 20 | | | | | | | | | |
| Granite Ridge | Sch. 6, ln 21 | | | | | | | | | |
| Subtotal Pipeline Commodity Costs | | $ - | $ 3,596,339 | $ 4,307,613 | $ 6,064,958 | $ 5,085,096 | $ 3,830,237 | $ 3,683,307 | | $ 26,567,550 |
| Storage: | | | | | | | | | | |
| TGP Storage - Withdrawals | Sch. 6, ln 47 | $ - | $ 543,878 | $ 2,138,887 | $ 2,575,290 | $ 2,209,739 | $ 1,631,633 | $ 22,276 | | $ 9,121,704 |
| Produced Gas Costs: | | | | | | | | | | |
| LNG Vapor | Sch. 6, ln 50 | | | | | | | | | |
| Propane | Sch. 6, ln 51 | | | | | | | | | |
| Subtotal Produced Gas Costs | | $ - | $ 8,385 | $ 8,483 | $ 251,683 | $ 7,362 | $ 7,862 | $ 7,591 | | $ 291,366 |
| Less Storage Refills: | | | | | | | | | | |
| LNG Truck | Sch. 6, ln 37 | | | | | | | | | |
| Propane | Sch. 6, ln 38 | | | | | | | | | |
| TGP Storage Refill | Sch. 6, ln 39 | | | | | | | | | |
| Storage Refill (Trans.) | Sch. 6, ln 40 | | | | | | | | | |
| Subtotal Storage Refill | | $ - | $ (655,834) | $ (7,528) | $ (238,320) | $ - | $ (15,610) | $ (886,634) | | $ (1,803,927) |
| Total Supply Commodity Costs | | $ - | $ 3,492,768 | $ 6,447,455 | $ 8,653,611 | $ 7,302,197 | $ 5,454,121 | $ 2,826,540 | | $ 34,176,693 |
| **C. Supply Volumetric Transportation Costs:** | | | | | | | | | | |
| Dawn Supply | Sch. 6, ln 26 | | | | | | | | | |
| Niagara Supply | Sch. 6, ln 27 | | | | | | | | | |
| TGP Supply (Direct) | Sch. 6, ln 28 | | | | | | | | | |
| Dracut Supply 1 - Baseload | Sch. 6, ln 29 | | | | | | | | | |
| Dracut Supply 2 - Swing | Sch. 6, ln 30 | | | | | | | | | |
| Subtotal Pipeline Volumetric Trans. Costs | | $ - | $ 250,777 | $ 252,463 | $ 265,685 | $ 240,581 | $ 251,813 | $ 254,506 | | $ 1,515,825 |
| TGP Storage - Withdrawals | Sch. 6, ln 32 | $ - | $ 20,940 | $ 82,349 | $ 99,151 | $ 85,077 | $ 62,819 | $ 884 | | $ 351,219 |
| Total Supply Volumetric Trans. Costs | lns 139 + 141 | $ - | $ 271,717 | $ 334,812 | $ 364,836 | $ 325,657 | $ 314,632 | $ 255,390 | | $ 1,867,044 |
| Total Commodity Gas & Trans. Costs | lns 131 + 143 | $ - | $ 3,764,485 | $ 6,782,267 | $ 9,018,447 | $ 7,627,855 | $ 5,768,753 | $ 3,081,930 | | $ 36,043,738 |

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**ENERGY NORTH NATURAL GAS, INC.**

**Peak 2012 - 2013 Winter Cost of Gas Filing**
**Summary of Supply and Demand Forecast**

| For Month of: | | Peak Costs May 12 - Oct 12 | Nov-12 | Dec-12 | Jan-13 | Feb-13 | Mar-13 | Apr-13 | May-13 | Peak Period Nov - Apr |
|---|---|---|---|---|---|---|---|---|---|---|
| **D. Supply and Demand Costs by Source** | | | | | | | | | | |
| Purchased Gas Demand Costs | | | | | | | | | | |
| Pipeline Gas Demand Costs | lns 54 + 73 | $ 1,363,979 | $ 1,072,998 | $ 1,073,033 | $ 1,073,033 | $ 1,072,927 | $ 1,073,033 | $ 1,072,998 | | $ 7,802,000 |
| Peaking Gas Demand Costs | ln 81 | 2,026,707 | 316,420 | 441,170 | 441,170 | 441,170 | 441,170 | 316,420 | | 4,424,227 |
| Subtotal Purchased Gas Demand Costs | | $ 3,390,686 | $ 1,389,418 | $ 1,514,203 | $ 1,514,203 | $ 1,514,097 | $ 1,514,203 | $ 1,389,418 | | $ 12,226,227 |
| Less Capacity Credit | lns 55 + 74 + 82 | (868,607) | (300,600) | (327,597) | (327,597) | (327,574) | (327,597) | (300,600) | | (2,780,171) |
| Net Purchased Gas Demand Costs | | $ 2,522,079 | $ 1,088,818 | $ 1,186,606 | $ 1,186,606 | $ 1,186,523 | $ 1,186,606 | $ 1,088,818 | | $ 9,446,057 |
| Storage Gas Demand Costs | | | | | | | | | | |
| Storage Demand | ln 93 | $ 715,492 | $ 119,249 | $ 119,249 | $ 119,249 | $ 119,249 | $ 119,249 | $ 119,249 | | $ 1,430,985 |
| Less Capacity Credit | ln 94 | (183,291) | (25,799) | (25,799) | (25,799) | (25,799) | (25,799) | (25,799) | | (338,087) |
| Net Storage Demand Costs | | $ 532,202 | $ 93,449 | $ 93,449 | $ 93,449 | $ 93,449 | $ 93,449 | $ 93,449 | | $ 1,092,898 |
| **Total Demand Costs** | lns 155 + 160 | $ 3,054,281 | $ 1,182,267 | $ 1,280,055 | $ 1,280,055 | $ 1,279,973 | $ 1,280,055 | $ 1,182,267 | | $ 10,538,954 |
| Purchased Gas Supply | | | | | | | | | | |
| Commodity Costs | ln 114 | $ - | $ 3,596,339 | $ 4,307,613 | $ 6,064,958 | $ 5,085,096 | $ 3,830,237 | $ 3,683,307 | | $ 26,567,550 |
| Less Storage Inj.(TGP Storage) | ln 127 | [redacted] | | | | | | | | |
| Less Storage Transportation | ln 128 | | | | | | | | | |
| Less LNG Truck | ln 125 | | | | | | | | | |
| Less Propane Truck | ln 126 | | | | | | | | | |
| Plus Transportation Costs | ln 139 | | | | | | | | | |
| Subtotal Purchased Gas Supply | | $ - | $ 3,191,282 | $ 4,552,548 | $ 6,092,323 | $ 5,325,677 | $ 4,066,439 | $ 3,051,179 | | $ 26,279,448 |
| Storage Commodity Costs | | | | | | | | | | |
| Commodity Costs | ln 117 | $ - | $ 543,878 | $ 2,138,887 | $ 2,575,290 | $ 2,209,739 | $ 1,631,633 | $ 22,276 | | $ 9,121,704 |
| Transportation Costs | ln 141 | - | 20,940 | 82,349 | 99,151 | 85,077 | 62,819 | 884 | | 351,219 |
| Subtotal Storage Commodity Costs | | $ - | $ 564,817 | $ 2,221,236 | $ 2,674,441 | $ 2,294,815 | $ 1,694,452 | $ 23,161 | | $ 9,472,923 |
| Produced Gas Commodity Costs | ln 122 | $ - | $ 8,385 | $ 8,483 | $ 251,683 | $ 7,362 | $ 7,862 | $ 7,591 | | $ 291,366 |
| **SubTotal Commodity Costs** | lns 171 + 176 + 178 | $ - | $ 3,764,485 | $ 6,782,267 | $ 9,018,447 | $ 7,627,855 | $ 5,768,753 | $ 3,081,930 | | $ 36,043,738 |
| Hedge Contract (Savings)/Loss | Sch 7, ln 32 | $ - | $ 341,683 | $ 338,706 | $ 315,594 | $ 323,001 | $ 420,983 | $ 201,674 | | $ 1,941,641 |
| **Total Commodity Costs** | lns 180 + 182 | $ - | $ 4,106,169 | $ 7,120,973 | $ 9,334,041 | $ 7,950,856 | $ 6,189,736 | $ 3,283,604 | | $ 37,985,379 |
| **Total Demand Costs** | ln 99 | $ 3,054,281 | $ 1,182,267 | $ 1,280,055 | $ 1,280,055 | $ 1,279,973 | $ 1,280,055 | $ 1,182,267 | | $ 10,538,954 |
| **Total Supply Costs** | ln 184 | - | 4,106,169 | 7,120,973 | 9,334,041 | 7,950,856 | 6,189,736 | 3,283,604 | | 37,985,379 |
| **Total Direct Gas Costs** | lns 186 + 187 | $ 3,054,281 | $ 5,288,436 | $ 8,401,028 | $ 10,614,096 | $ 9,230,829 | $ 7,469,791 | $ 4,465,871 | | $ 48,524,333 |

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**ENERGY NORTH NATURAL GAS, INC.**

**Peak 2012 - 2013 Winter Cost of Gas Filing**
**Contracts Ranked on a per Unit Cost Basis**

| Supplier | Contract | Contract Type | Contract Unit | Unit Dth (MDQ/ACQ) | Peak Period Cost per Unit Dth |
|---|---|---|---|---|---|
| (a) | (b) | (c) | (d) | (e) | (f) |
| **Demand Costs** | | | | | |
| Dominion - Capacity Reservation | GSS 300076 | Storage | ACQ | 102,700 | [redacted] |
| Tenn Gas Pipeline - Cap. Reservations | FS-MA | Storage | ACQ | 1,560,391 | |
| National Fuel - Capacity Reservation | FSS-1 2357 | Storage | ACQ | 670,800 | |
| Niagra Supply | | Supply | MDQ | 3,199 | |
| Tenn Gas Pipeline - Demand | FS-MA | Storage | MDQ | 21,844 | |
| Dominion - Demand | GSS 300076 | Storage | MDQ | 934 | |
| National Fuel - Demand | FSS-1 2357 | Storage | MDQ | 6,098 | |
| National Fuel | FST 2358 | Transportation | MDQ | 6,098 | |
| Tenn Gas Pipeline | 42076 FTA Z6-Z6 | Transportation | MDQ | 20,000 | |
| Honeoye - Demand | SS-NY | Storage | MDQ | 1,362 | |
| Iroquois Gas Trans Service | RTS 470-01 | Transportation | MDQ | 4,047 | |
| Tenn Gas Pipeline | 2302 Z5-Z6 | Transportation | MDQ | 3,122 | |
| Tenn Gas Pipeline | 95346 Z5-Z6 | Transportation | MDQ | 4,000 | |
| Tenn Gas Pipeline (short haul) | 11234 Z5-Z6(stg) | Transportation | MDQ | 1,957 | |
| Tenn Gas Pipeline (short haul) | 11234 Z4-Z6(stg) | Transportation | MDQ | 7,082 | |
| Tenn Gas Pipeline (short haul) | 8587 Z4-Z6 | Transportation | MDQ | 3,811 | |
| Tenn Gas Pipeline (short haul) | 632 Z4-Z6 (stg) | Transportation | MDQ | 15,265 | |
| Tenn Gas Pipeline (Concord Lateral) Z6-Z6 | 72694 Z6-Z6 | Transportation | MDQ | 30,000 | |
| ANE (TransCanada via Union to Iroquois) | Union Parkway to Iroquois | Transportation | MDQ | 4,047 | |
| Tenn Gas Pipeline (long haul) | 8587 Z1-Z6 | Transportation | MDQ | 14,561 | |
| Tenn Gas Pipeline (long haul) | 8587 Z0-Z6 | Transportation | MDQ | 7,035 | |
| Portland Natural Gas Trans Service | FT-1999-001 | Transportation | MDQ | 1,000 | |
| DOMAC Liquid Demand Charge | NSB041 | Peaking | MDQ | - | |
| Granite Ridge Demand | | Peaking | MDQ | - | |
| **Supply Costs - Commodity** | | | | | |
| City Gate Delivered Supply | | Pipeline | Dkt | - | [redacted] |
| LNG Truck | | Pipeline | Dkt | 76,923 | |
| TGP Supply (Direct) | | Pipeline | Dkt | 3,068,681 | |
| LNG Vapor (Storage) | | Produced | Dkt | 81,928 | |
| Dawn Supply | | Pipeline | Dkt | 544,236 | |
| Niagara Supply | | Pipeline | Dkt | 435,204 | |
| PNGTS | | Pipeline | Dkt | 40,348 | |
| Granite Ridge | | Pipeline | Dkt | - | |
| Dracut Supply 2 - Swing | | Pipeline | Dkt | 1,497,958 | |
| Dracut Supply 1 - Baseload | | Pipeline | Dkt | 691,229 | |
| TGP Storage | | Storage | Dkt | 2,052,281 | |
| Propane | | Produced | Dkt | - | |
| Propane Truck | | Pipeline | Dkt | - | |
| **Supply Costs - Volumetric Transportation** | | | | | |
| Dracut Supply 1 - Baseload | | Pipeline | Dkt | 691,229 | [redacted] |
| Dracut Supply 2 - Swing | | Pipeline | Dkt | 1,497,958 | |
| Niagara Supply | | Pipeline | Dkt | 435,204 | |
| Dawn Supply | | Pipeline | Dkt | 544,236 | |
| TGP Storage - Withdrawals | | Pipeline | Dkt | 2,052,281 | |
| TGP Supply (Direct) | | Pipeline | Dkt | 3,068,681 | |

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**ENERGY NORTH NATURAL GAS, INC.**

**Peak 2012 - 2013 Winter Cost of Gas Filing**
**COG (Over)/Under Cumulative Recovery Balances and Interest Calculation**

| | | | Prior Period Balance Apr-12 Ending Bal | May-12 | Jun-12 | Jul-12 | Aug-12 | Sep-12 | Oct-12 | Nov-12 | Dec-12 | Jan-13 | Feb-13 | Mar-13 | Apr-13 | May-13 | Peak Period Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | Days in Month (b) | Plus May Billings (c) | 31 (d) | 30 (e) | 31 (f) | 31 (g) | 30 (h) | 31 (i) | 30 (j) | 31 (k) | 31 (l) | 28 (m) | 31 (n) | 30 (o) | 31 (p) | (q) |
| **Accunt 175.20 COG (Over)/Under Balance - Interest Calculation** | | | | | | | | | | | | | | | | | |
| | **Beginning Balance** | Account 175.20 1/ | **$ 2,076,323** | $ 1,606,569 | $ 2,099,536 | $ 2,284,820 | $ 2,564,516 | $ 2,889,180 | $ 3,291,182 | $ 3,680,549 | $ 2,964,304 | $ 2,045,049 | $ 1,612,140 | $ 1,212,023 | $ 316,146 | $ (79,762) | $ 2,076,323 |
| | Fcst Direct Gas Costs(Inc U/G Hedges) | Schedule 5A | | 509,047 | 509,047 | 509,047 | 509,047 | 509,047 | 509,047 | 5,288,436 | 8,401,028 | 10,614,096 | 9,230,829 | 7,469,791 | 4,465,871 | - | 48,524,333 |
| | Production & Storage & Misc Overhead | | | - | - | - | - | - | - | 331,860 | 331,860 | 331,860 | 331,860 | 331,860 | 331,860 | | 1,991,163 |
| | Projected Revenues w/o Int. | ln 52 * 59 | | - | - | - | - | - | - | (1,326,639) | (7,366,476) | (10,905,586) | (11,666,178) | (10,085,430) | (6,775,749) | (2,609,483) | (50,735,540) |
| | Projected Unbilled Revenue | | | | | | | | | (4,985,754) | (7,210,333) | (7,633,350) | (5,858,513) | (4,436,335) | (2,761,544) | | (32,885,829) |
| | Reverse Prior Month Unbilled | | | | | | | | | | 4,985,754 | 7,210,333 | 7,633,350 | 5,858,513 | 4,436,335 | 2,761,544 | 32,885,829 |
| | Prior Period Adjustment-Unbilled | | | | - | | | | | - | | | | | | | - |
| | Add Net Adjustments | Schedule 4 | | (21,835) | (329,611) | (236,034) | (191,899) | (115,288) | (129,289) | (33,012) | (67,993) | (55,303) | (74,980) | (36,384) | (92,997) | - | (1,384,626) |
| | Gas Cost Billed | Account 175.20 2/ | (469,754) | - | - | - | - | - | - | - | - | - | - | - | - | - | (469,754) |
| | Monthly (Over)/Under Recovery | | $ 1,606,569 | $ 2,093,781 | $ 2,278,972 | $ 2,557,832 | $ 2,881,664 | $ 3,282,939 | $ 3,670,940 | $ 2,955,441 | $ 2,038,145 | $ 1,607,100 | $ 1,208,507 | $ 314,039 | $ (80,077) | $ 72,299 | $ 1,898 |
| | Average Monthly Balance | (ln 12 + 21)/2 | | $ 2,085,052 | $ 2,189,254 | $ 2,421,326 | $ 2,723,090 | $ 3,086,059 | $ 3,481,061 | $ 3,317,995 | $ 2,501,225 | $ 1,826,075 | $ 1,410,324 | $ 763,031 | $ 118,034 | $ (3,731) | |
| | Interest Rate | Prime Rate | | 3.25% | 3.25% | 3.25% | 3.25% | 3.25% | 3.25% | 3.25% | 3.25% | 3.25% | 3.25% | 3.25% | 3.25% | | |
| | Interest Applied | ln 22 * ln 24 / 365 * Days of Month | | $ 5,755 | $ 5,848 | $ 6,684 | $ 7,516 | $ 8,244 | $ 9,609 | $ 8,863 | $ 6,904 | $ 5,040 | $ 3,516 | $ 2,106 | $ 315 | $ - | $ 70,401 |
| | **(Over)/Under Balance** | ln 21 + ln 26 | $ 1,606,569 | $ 2,099,536 | $ 2,284,820 | $ 2,564,516 | $ 2,889,180 | $ 3,291,182 | $ 3,680,549 | $ 2,964,304 | $ 2,045,049 | $ 1,612,140 | $ 1,212,023 | $ 316,146 | $ (79,762) | $ 72,299 | 72,299 |
| **Calculation of COG with Interest** | | | | | | | | | | | | | | | | | |
| | **Beginning Balance** | ln 12 | $ 2,076,323 | $ 1,606,569 | $ 2,099,536 | $ 2,284,820 | $ 2,564,516 | $ 2,889,180 | $ 3,291,182 | $ 3,680,549 | $ 2,955,598 | $ 2,023,081 | $ 1,574,471 | $ 1,160,604 | $ 252,622 | $ (150,500) | $ 2,076,323 |
| | Fcst Direct Gas Costs(Inc U/G Hedges) | ln 13 | | 509,047 | 509,047 | 509,047 | 509,047 | 509,047 | 509,047 | 5,288,436 | 8,401,028 | 10,614,096 | 9,230,829 | 7,469,791 | 4,465,871 | - | 48,524,333 |
| | Prod Storage & Misc Overhead | ln 14 | | - | - | - | - | - | - | 331,860 | 331,860 | 331,860 | 331,860 | 331,860 | 331,860 | - | 1,991,163 |
| | Projected Revenues with int. | ln 52 * ln 61 | | - | - | - | - | - | - | (1,328,468) | (7,376,636) | (10,920,628) | (11,682,270) | (10,099,341) | (6,785,095) | (2,613,082) | (50,805,520) |
| | Projected Unbilled Revenue | | | | | | | | | (4,992,631) | (7,220,278) | (7,643,879) | (5,866,594) | (4,442,454) | (2,765,353) | | (32,931,189) |
| | Reverse Prior Month Unbilled | | | | | | | | | | 4,992,631 | 7,220,278 | 7,643,879 | 5,866,594 | 4,442,454 | 2,765,353 | 32,931,189 |
| | Add Net Adjustments | ln 19 | | (21,835) | (329,611) | (236,034) | (191,899) | (115,288) | (129,289) | (33,012) | (67,993) | (55,303) | (74,980) | (36,384) | (92,997) | - | (1,384,626) |
| | Gas Cost Billed | ln 20 | (469,754) | - | - | - | - | - | - | - | - | - | - | - | - | - | (469,754) |
| | Add Interest | ln 26 | | - | - | - | - | - | - | 8,863 | 6,904 | 5,040 | 3,516 | 2,106 | 315 | - | 26,745 |
| | **(Over)/Under Balance** | | $ 1,606,569 | $ 2,093,781 | $ 2,278,972 | $ 2,557,832 | $ 2,881,664 | $ 3,282,939 | $ 3,670,940 | $ 2,955,597 | $ 2,023,114 | $ 1,574,546 | $ 1,160,711 | $ 252,777 | $ (150,321) | $ 1,771 | $ (41,336) |
| | Average Monthly Balance | | | $ 2,085,052 | $ 2,189,254 | $ 2,421,326 | $ 2,723,090 | $ 3,086,059 | $ 3,481,061 | $ 3,318,073 | $ 2,489,356 | $ 1,798,814 | $ 1,367,591 | $ 706,691 | $ 51,150 | $ (74,365) | |
| | Interest Applied | ln 24 * ln 44 / 365 * Days of Month | | 5,755 | 5,848 | 6,684 | 7,516 | 8,244 | 9,609 | 8,863 | 6,871 | 4,965 | 3,410 | 1,951 | 137 | - | 69,852 |
| | **(Over)/Under Balance** | -ln 41 +ln 42 + ln 46 | $ 1,606,569 | $ 2,099,536 | $ 2,284,820 | $ 2,564,516 | $ 2,889,180 | $ 3,291,182 | $ 3,680,549 | $ 2,955,598 | $ 2,023,081 | $ 1,574,471 | $ 1,160,604 | $ 252,622 | $ (150,500) | $ 1,771 | 1,771 |
| | Forecast Sendout Therms | Sch 1 | | | | | | | | 9,922,220 | 15,075,830 | 17,807,020 | 15,547,840 | 13,617,450 | 8,018,010 | | 79,988,370 |
| | Less Forecast Billing Therm Sales | Sch. 10B, ln 23 Nov - May | | | | | | | | 2,033,163 | 11,289,618 | 16,713,541 | 17,879,201 | 15,456,597 | 10,384,290 | 3,999,207 | 77,755,617 |
| | Less Forecast Unaccounted For | Sch 1 | | | | | | | | 166,779 | 253,405 | 299,313 | 261,339 | 228,891 | 134,772 | | 1,344,499 |
| | Less Forecast Company Use | Sch 1 | | | | | | | | 81,276 | 123,491 | 145,863 | 127,357 | 111,545 | 65,678 | | 655,210 |
| | Unbilled Volumes | | | | | | | | | 7,641,002 | 3,409,316 | 648,303 | -2,720,057 | -2,179,583 | -2,566,730 | -3,999,207 | 233,044 |
| | Gross Unbilled | | | | | | | | | 7,641,002 | 11,050,318 | 11,698,621 | 8,978,565 | 6,798,981 | 4,232,251 | 233,044 | |
| | COB w/o Interest | Sch. 3, pg. 4, ln 211 col. (c) | | | | | | | | $0.6525 | $0.6525 | $0.6525 | $0.6525 | $0.6525 | $0.6525 | $0.6525 | |
| | COG With Interest | Sch. 3, pg. 4, ln 211 col. (d) | | | | | | | | $0.6534 | $0.6534 | $0.6534 | $0.6534 | $0.6534 | $0.6534 | $0.6534 | |

1/ Beginning Balance for Acct 175.20. See Tab 18, Schedule 1, page 1, line 31, April 2010 column.
2/ Gas Cost Billed Acct 175.20. See Tab 18, Schedule 1, page 1, line 15, May 2010 column.

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**ENERGY NORTH NATURAL GAS, INC.**

**Peak 2012 - 2013 Winter Cost of Gas Filing**
**COG (Over)/Under Cumulative Recovery Balances and Interest Calculation**

| | | | Prior Period Balance | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Apr-12 | May-12 | Jun-12 | Jul-12 | Aug-12 | Sep-12 | Oct-12 | Nov-12 | Dec-12 | Jan-13 | Feb-13 | Mar-13 | Apr-13 | May-13 | Peak Period |
| | | Days in Month | Ending Bal | 31 | 30 | 31 | 31 | 30 | 31 | 30 | 31 | 31 | 28 | 31 | 30 | 31 | Total |
| | (a) | (b) | Plus May Collections | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) | (n) | (o) | (p) |
| **Accunt 142.20 Working Capital (Over)/Under Balance - Interest Calculation** | | | | | | | | | | | | | | | | | |
| **Beginning Balance** | Account 142.20 1/ | | $ 64 | $ (541) | $ 106 | $ 754 | $ 1,404 | $ 2,056 | $ 2,709 | $ 3,365 | $ 2,354 | $ 1,277 | $ 879 | $ 485 | $ (644) | $ (1,224) | $ 64 |
| Days Lag | | | | 0.0391 | 0.0391 | 0.0391 | 0.0391 | 0.0391 | 0.0391 | 0.0391 | 0.0391 | 0.0391 | 0.0391 | 0.0391 | 0.0391 | | |
| Prime Rate | | | | 3.25% | 3.25% | 3.25% | 3.25% | 3.25% | 3.25% | 3.25% | 3.25% | 3.25% | 3.25% | 3.25% | 3.25% | | |
| Forecast Working Capital | ln 34 * 0.091% | | | 647 | 647 | 647 | 647 | 647 | 647 | 6,721 | 10,677 | 13,489 | 11,731 | 9,493 | 5,676 | - | 61,669 |
| Projected Revenues w/o Int. | ln 121 * ln 125 | | | - | - | - | - | - | - | (1,627) | (9,032) | (13,371) | (14,303) | (12,365) | (8,307) | (3,199) | (62,204) |
| Projected Unbilled Revenue | | | | | | | | | | (6,113) | (8,840) | (9,359) | (7,183) | (5,439) | (3,386) | | (40,320) |
| Reverse Prior Month Unbilled | | | | | | | | | | | 6,113 | 8,840 | 9,359 | 7,183 | 5,439 | 3,386 | 40,320 |
| Add Net Adjustments | | | | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Working Capital Billed | Account 142.20 2/ | | (604) | | | | | | | | | | | | | | (604) |
| Monthly (Over)/Under Recovery | | | $ (541) | $ 106 | $ 753 | $ 1,401 | $ 2,051 | $ 2,703 | $ 3,356 | $ 2,346 | $ 1,272 | $ 876 | $ 483 | $ (643) | $ (1,222) | $ (1,038) | $ (1,076) |
| Average Monthly Balance | (ln 78 + ln 92)/2 | | | $ 85 | $ 430 | $ 1,078 | $ 1,728 | $ 2,380 | $ 3,033 | $ 2,856 | $ 1,813 | $ 1,076 | $ 681 | $ (79) | $ (933) | $ (1,131) | |
| Interest Rate | Prime Rate | | | 3.25% | 3.25% | 3.25% | 3.25% | 3.25% | 3.25% | 3.25% | 3.25% | 3.25% | 3.25% | 3.25% | 3.25% | | |
| Interest Applied | ln 94 * ln 96 / 365 * Days of Month | | | $ 0 | $ 1 | $ 3 | $ 5 | $ 6 | $ 8 | $ 8 | $ 5 | $ 3 | $ 2 | $ (0) | $ (2) | $ - | $ 38 |
| **(Over)/Under Balance** | ln 92 + ln 98 | | $ (541) | $ 106 | $ 754 | $ 1,404 | $ 2,056 | $ 2,709 | $ 3,365 | $ 2,354 | $ 1,277 | $ 879 | $ 485 | $ (644) | $ (1,224) | $ (1,038) | (1,038) |
| **Calculation of Working Capital with Interest** | | | | | | | | | | | | | | | | | |
| **Beginning Balance** | ln 78 | | $ 64 | $ (541) | $ 106 | $ 754 | $ 1,404 | $ 2,056 | $ 2,709 | $ 3,365 | $ 2,354 | $ 1,277 | $ 879 | $ 485 | $ (644) | $ (1,224) | $ 64 |
| Forecast Working Capital | ln 82 | | | 647 | 647 | 647 | 647 | 647 | 647 | 6,721 | 10,677 | 13,489 | 11,731 | 9,493 | 5,676 | - | 61,669 |
| Projected Rev. with interest | ln 121 * ln 127 | | | - | - | - | - | - | - | (1,627) | (9,032) | (13,371) | (14,303) | (12,365) | (8,307) | (3,199) | (62,204) |
| Projected Unbilled Revenue | | | | | | | | | | (6,113) | (8,840) | (9,359) | (7,183) | (5,439) | (3,386) | | (40,320) |
| Reverse Prior Month Unbilled | | | | | | | | | | | 6,113 | 8,840 | 9,359 | 7,183 | 5,439 | 3,386 | 40,320 |
| Add Net Adjustments | ln 88 | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Working Capital Billed | ln 90 | | (604) | - | - | - | - | - | - | | | | | | | | (604) |
| Add Interest | ln 98 | | | - | - | - | - | - | - | 8 | 5 | 3 | 2 | (0) | (2) | - | 15 |
| Monthly (Over)/Under Recovery | | | $ (541) | $ 106 | $ 753 | $ 1,401 | $ 2,051 | $ 2,703 | $ 3,356 | $ 2,354 | $ 1,277 | $ 879 | $ 485 | $ (644) | $ (1,224) | $ (1,038) | $ (1,062) |
| Average Monthly Balance | | | | $ 85 | $ 430 | $ 1,078 | $ 1,728 | $ 2,380 | $ 3,033 | $ 2,859 | $ 1,815 | $ 1,078 | $ 682 | $ (79) | $ (934) | $ (1,131) | |
| Interest Applied | ln 96 * ln 115 / 365 * Days of Month | | | 0 | 1 | 3 | 5 | 6 | 8 | 8 | 5 | 3 | 2 | (0) | (2) | - | $ 38 |
| **(Over)/Under Balance** | -ln 112 +ln 113 + ln 117 | | $ (541) | $ 106 | $ 754 | $ 1,404 | $ 2,056 | $ 2,709 | $ 3,365 | $ 2,354 | $ 1,277 | $ 879 | $ 485 | $ (644) | $ (1,224) | $ (1,038) | $ (1,038) |
| Forecast Therm Sales | ln 52 | | | | | | | | | 2,033,163 | 11,289,618 | 16,713,541 | 17,879,201 | 15,456,597 | 10,384,290 | 3,999,207 | 77,755,617 |
| Unbilled Therm | ln 55 | | | | | | | | | 7,641,002 | 3,409,316 | 648,303 | (2,720,057) | (2,179,583) | (2,566,730) | | |
| Gross Unbilled | | | | | | | | | | 7,641,002 | 11,050,318 | 11,698,621 | 8,978,565 | 6,798,981 | 4,232,251 | | |
| Working Cap. Rate w/out Int. | Sch. 3, pg. 4, ln 228 col. (c) | | | | | | | | | $0.0008 | $0.0008 | $0.0008 | $0.0008 | $0.0008 | $0.0008 | $0.0008 | |
| Working Capital Rate w/ Int. | Sch. 3, pg. 4, ln 228 col. (d) | | | | | | | | | $0.0008 | $0.0008 | $0.0008 | $0.0008 | $0.0008 | $0.0008 | $0.0008 | |

1/ Beginning Balance for Acct 142.20. See Tab 18 Schedule 5, page 1, line 18, April 2010 column.
2/ Working Capital Billed Acct 142.20. See Tab 18, Schedule 5, page 1, line 8, May 2010 column.

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**ENERGY NORTH NATURAL GAS, INC.**

**Peak 2012 - 2013 Winter Cost of Gas Filing**
**COG (Over)/Under Cumulative Recovery Balances and Interest Calculation**

| | | | Prior Period Balance | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Apr-12 | May-12 | Jun-12 | Jul-12 | Aug-12 | Sep-12 | Oct-12 | Nov-12 | Dec-12 | Jan-13 | Feb-13 | Mar-13 | Apr-13 | May-13 | DemandPeriod |
| | | Days in Month | Ending Bal | 31 | 30 | 31 | 31 | 30 | 31 | 30 | 31 | 31 | 28 | 31 | 30 | 31 | Total |
| | (a) | (b) | Plus May Collections | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) | (n) | (o) | (p) |
| **Accunt 175.52 Bad Debt (Over)/Under Balance - Interest Calculation** | | | | | | | | | | | | | | | | | |
| Forecast Direct Gas Costs | ln 34 | | | $ 509,047 | $ 509,047 | $ 509,047 | $ 509,047 | $ 509,047 | $ 509,047 | $ 5,288,436 | $ 8,401,028 | $ 10,614,096 | $ 9,230,829 | $ 7,469,791 | $ 4,465,871 | $ - | 48,524,333 |
| Forecast Working Capital | ln 106 | | | 647 | 647 | 647 | 647 | 647 | 647 | 6,180 | 10,677 | 13,489 | 11,731 | 9,493 | 5,676 | | 61,128 |
| Prior Period Balance | ln 42 | | | | | | | | | 267,761 | 267,761 | 267,761 | 267,761 | 267,761 | 267,761 | | 1,606,569 |
| Total Forecast Direct Gas Costs & Working Capital | | | | 509,694 | 509,694 | 509,694 | 509,694 | 509,694 | 509,694 | 5,562,378 | 8,679,466 | 10,895,347 | 9,510,321 | 7,747,046 | 4,739,308 | - | 48,585,461 |
| **Beginning Balance** | Account 175.52 1/ | | **$ 124,588** | $ 113,348 | $ 126,436 | $ 139,533 | $ 152,678 | $ 165,860 | $ 179,062 | $ 192,316 | $ 161,582 | $ 120,256 | $ 87,358 | $ 58,496 | $ 18,603 | $ (479) | $ 124,588 |
| Forecast Bad Debt | ln 140 * 0.025 | | | 12,742 | 12,742 | 12,742 | 12,742 | 12,742 | 12,742 | 139,059 | 216,987 | 272,384 | 237,758 | 193,676 | 118,483 | | 1,254,801 |
| Projected Revenues w/o int | ln 183 * ln 187 | | | - | - | - | - | - | - | (35,784) | (198,697) | (294,158) | (314,674) | (272,036) | (182,764) | (70,386) | (1,368,499) |
| Projected Unbilled Revenue | | | | | | | | | | (134,482) | (194,486) | (205,896) | (158,023) | (119,662) | (74,488) | | (887,035) |
| Reverse Prior Month Unbilled | | | | | | | | | | | 134,482 | 194,486 | 205,896 | 158,023 | 119,662 | 74,488 | 887,035 |
| Bad Debt Billed | Account 175.52 2/ | | (11,241) | | - | - | - | - | - | | - | - | - | - | - | - | (11,241) |
| Add Net Adjustments | | | - | - | - | - | - | - | - | | - | - | - | - | - | - | - |
| Monthly (Over)/Under Recovery | | | $ 113,348 | $ 126,090 | $ 139,178 | $ 152,275 | $ 165,421 | $ 178,602 | $ 191,804 | $ 161,110 | $ 119,868 | $ 87,071 | $ 58,315 | $ 18,497 | $ (503) | $ 3,623 | $ (350) |
| Average Monthly Balance | (ln 142 + ln 154)/2 | | | $ 125,339 | $ 132,807 | $ 145,904 | $ 159,049 | $ 172,231 | $ 185,433 | $ 176,713 | $ 140,725 | $ 103,664 | $ 72,836 | $ 38,497 | $ 9,050 | $ 1,572 | |
| Interest Rate | Prime Rate | | | 3.25% | 3.25% | 3.25% | 3.25% | 3.25% | 3.25% | 3.25% | 3.25% | 3.25% | 3.25% | 3.25% | 3.25% | | |
| Interest Applied | ln 156 * ln 158 / 365 * Days of Month | | | $ 346 | $ 355 | $ 403 | $ 439 | $ 460 | $ 512 | $ 472 | $ 388 | $ 286 | $ 182 | $ 106 | $ 24 | | $ 3,973 |
| **(Over)/Under Balance** | ln 154 + ln 160 | | $ 113,348 | $ 126,436 | $ 139,533 | $ 152,678 | $ 165,860 | $ 179,062 | $ 192,316 | $ 161,582 | $ 120,256 | $ 87,358 | $ 58,496 | $ 18,603 | $ (479) | $ 3,623 | 3,623 |
| **Calculation of Bad Debt with Interest** | | | | | | | | | | | | | | | | | |
| **Beginning Balance** | ln 142 | | $ 124,588 | $ 113,348 | $ 126,436 | $ 139,533 | $ 152,678 | $ 165,860 | $ 179,062 | $ 192,316 | $ 161,583 | $ 120,257 | $ 87,359 | $ 58,497 | $ 18,604 | $ (478) | $ 124,588 |
| Forecast Bad Debt | ln 144 | | | 12,742 | 12,742 | 12,742 | 12,742 | 12,742 | 12,742 | 139,059 | 216,987 | 272,384 | 237,758 | 193,676 | 118,483 | - | 1,254,801 |
| Projected Revenues with int. | ln 183 * ln 189 | | | - | - | - | - | - | - | (35,784) | (198,697) | (294,158) | (314,674) | (272,036) | (182,764) | (70,386) | (1,368,499) |
| Projected Unbilled Revenue | | | | | | | | | | (134,482) | (194,486) | (205,896) | (158,023) | (119,662) | (74,488) | | (887,035) |
| Reverse Prior Month Unbilled | | | | | | | | | | | 134,482 | 194,486 | 205,896 | 158,023 | 119,662 | 74,488 | 887,035 |
| Bad Debt Billed | ln 150 | | (11,241) | | - | - | - | - | - | - | - | - | - | - | - | - | (11,241) |
| Add Interest | ln 160 | | | - | - | - | - | - | - | 472 | 388 | 286 | 182 | 106 | 24 | - | 1,459 |
| Add Net Adjustments | ln 152 | | - | | | | | | | - | - | - | - | - | - | - | 0 |
| Monthly (Over)/Under Recovery | | | $ 113,348 | $ 126,090 | $ 139,178 | $ 152,275 | $ 165,421 | $ 178,602 | $ 191,804 | $ 161,582 | $ 120,257 | $ 87,359 | $ 58,497 | $ 18,604 | $ (478) | $ 3,624 | $ 1,108 |
| Average Monthly Balance | | | | $ 125,339 | $ 132,807 | $ 145,904 | $ 159,049 | $ 172,231 | $ 185,433 | $ 176,949 | $ 140,920 | $ 103,808 | $ 72,928 | $ 38,551 | $ 9,063 | $ 1,573 | |
| Interest Applied | ln 158 * ln 177 / 365 * Days of Month | | | 346 | 355 | 403 | 439 | 460 | 512 | 473 | 389 | 286 | 182 | 106 | 24 | - | $ 3,974 |
| **(Over)/Under Balance** | -ln 173 +ln 175 + ln 179 | | $ 113,348 | $ 126,436 | $ 139,533 | $ 152,678 | $ 165,860 | $ 179,062 | $ 192,316 | $ 161,583 | $ 120,257 | $ 87,359 | $ 58,497 | $ 18,604 | $ (478) | $ 3,624 | $ 3,624 |
| Forecast Term Sales | ln 52 | | | | | | | | | 2,033,163 | 11,289,618 | 16,713,541 | 17,879,201 | 15,456,597 | 10,384,290 | 3,999,207 | 77,755,617 |
| Unbilled Therm | ln 55 | | | | | | | | | 7,641,002 | 3,409,316 | 648,303 | (2,720,057) | (2,179,583) | (2,566,730) | | |
| Gross Unbilled | | | | | | | | | | 7,641,002 | 11,050,318 | 11,698,621 | 8,978,565 | 6,798,981 | 4,232,251 | | |
| COG Rate Without Interest | Sch. 3, pg. 4, ln 245 col. (c) | | | | | | | | | $0.0176 | $0.0176 | $0.0176 | $0.0176 | $0.0176 | $0.0176 | $0.0176 | |
| COG With Interest | Sch. 3, pg. 4, ln 245 col. (d) | | | | | | | | | $0.0176 | $0.0176 | $0.0176 | $0.0176 | $0.0176 | $0.0176 | $0.0176 | |
| **Total Interest** | lns 46 + 117 + 179 | | $ - | $ 6,102 | $ 6,204 | $ 7,089 | $ 7,960 | $ 8,710 | $ 10,129 | $ 9,344 | $ 7,265 | $ 5,254 | $ 3,593 | $ 2,057 | $ 158 | $ - | $ 73,865 |

1/ Beginning Balance for Acct 175.52. See Tab 18, Schedule 1, page 3, line 20, April 2010 column.
2/ Bad Debt Billed Acct 175.52. See Tab 18, Schedule 1, page 3, line 10, May 2010 column.

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**ENERGY NORTH NATURAL GAS, INC.**

**Peak 2012 - 2013 Winter Cost of Gas Filing**
**COG (Over)/Under Cumulative Recovery Balances and Interest Calculation**

| | | | COG Rate Without Interest | COG Rate With Interest |
|---|---|---|---|---|
| **Calculation of COG** | | | | |
| | (a) | (b) | (c) | (d) |
| | (Over)Under Recovery Balance | ln 12, col. (q) | $ 2,076,323 | $ 2,076,323 |
| | Unadjusted Forecast of Gas Costs | ln 13, col. (q) | 48,524,333 | 48,524,333 |
| | Production & Storage and Misc Overhea | ln 14, col. (q) | 1,991,163 | 1,991,163 |
| | Adjustments | ln 19, col. (q) | (1,854,380) | (1,854,380) |
| | Interest Nov -Apr | ln 46, col. (q) | - | $ 69,852 |
| | Total Gas To Be Recovered | | $ 50,737,438 | $ 50,807,291 |
| | Forecast Gas Sales (Nov - Apr) | ln 52, col. (q) | 77,755,617 | 77,755,617 |
| | Preliminary COG Rate | ln. 207 / ln. 209 | $0.6525 | $0.6534 |

| | | | Working Capital Rate without interest | Working Capital Rate with Interest |
|---|---|---|---|---|
| **Calculation of Working Capital Rate** | | | | |
| | (a) | (b) | (c) | (d) |
| | (Over)Under Recovery Balance | ln 78, col. (q) | $ 64 | $ 64 |
| | Unadjusted Working Capital Forecast | ln 82, col. (q) | 61,669 | 61,669 |
| | Adjustments without interest | ln 88, col. (q) | (604) | (604) |
| | Interest Nov -Apr | ln 117, col. (q) | - | $ 38 |
| | Total Gas To Be Recovered | | $ 61,128 | $ 61,166 |
| | Forecast Gas Sales (Nov - Apr) | ln 52, col. (q) | 77,755,617 | 77,755,617 |
| | Preliminary Working Capital COG Rate | | $0.0008 | $0.0008 |

| | | | Bad Debt Rate without Interest | Bad Debt Rate with interest |
|---|---|---|---|---|
| **Calculation of Bad Debt Rate** | | | | |
| | (a) | (b) | (c) | |
| | (Over)Under Recovery Balance | ln 142, col. (q) | $ 124,588 | $ 124,588 |
| | Unadjusted Bad Debt Forecast | ln 144, col. (q) | 1,254,801 | 1,254,801 |
| | Adjustments without interest | ln 152, col. (q) | (11,241) | (11,241) |
| | Interest Nov -Apr | ln 179, col. (q) | - | $ 3,974 |
| | Total Gas To Be Recovered | | $ 1,368,148 | $ 1,372,123 |
| | Forecast Gas Sales (Nov - Apr) | ln 52, col. (q) | 77,755,617 | 77,755,617 |
| | Preliminary Bad Debt COG Rate | | $0.0176 | $0.0176 |

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**ENERGY NORTH NATURAL GAS, INC.**

**Peak 2012 - 2013 Winter Cost of Gas Filing**
**Adjustments to Gas Costs**

| **Adjustments** | | **Prior Period Adjustments** | **Refunds from Suppliers** | **Broker Revenue** | **Inventory Finance Charges** | **Transportation CGA Revenues (Schedule 17)** | **Interruptible Sales Margin** | **Off System Sales Margin** | **Capacity Release** | **PCB Refunds** | **Fixed Price Option Administrative Costs** | **Total Adjustments** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (a) | | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (m) |
| May-12 | | $ - | $ - | $ (13,826) | $ 15,018 | $ - | [redacted] | | | $ - | $ - | $ (21,835) |
| Jun-12 | | - | - | (23,720) | 14,847 | - | | | | - | - | (329,611) |
| Jul-12 | 1/ | - | - | (64,173) | 5,636 | - | | | | - | - | (236,034) |
| Aug-12 | 1/ | - | - | (3,179) | 4,564 | - | | | | - | - | (191,899) |
| Sep-12 | 1/ | - | - | (16,097) | 4,422 | - | | | | - | - | (115,288) |
| Oct-12 | 1/ | - | - | (24,412) | 6,667 | - | | | | - | - | (129,289) |
| Nov-12 | 1/ | - | - | (59,962) | 13,915 | (947) | | | | - | 40,691 | (33,012) |
| Dec-12 | 1/ | - | - | (52,719) | 13,194 | (1,279) | | | | - | - | (67,993) |
| Jan-13 | 1/ | - | - | (37,893) | 11,178 | (1,616) | | | | - | - | (55,303) |
| Feb-13 | 1/ | - | - | (51,607) | 8,679 | (1,714) | | | | - | - | (74,980) |
| Mar-13 | 1/ | - | - | (10,518) | 6,151 | (1,503) | | | | - | - | (36,384) |
| Apr-13 | 1/ | - | - | (38,091) | 5,453 | (1,165) | | | | - | - | (92,997) |
| Subtotal May 12 - Oct 12 | | $ - | $ - | $ (145,407) | $ 51,154 | $ - | $ - | $ (264,466) | $ (665,237) | $ - | $ - | $ (1,023,956) |
| Subtotal Nov 12 - Apr 13 | | $ - | $ - | $ (250,790) | $ 58,570 | $ (8,224) | $ - | $ (9,497) | $ (191,419) | $ - | $ 40,691 | $ (360,669) |
| Total Peak Period | | $ - | $ - | $ (396,197) | $ 109,724 | $ (8,224) | $ - | $ (273,963) | $ (856,656) | $ - | $ 40,691 | $ (1,384,626) |

1/ Estimates are based on prior years actual. Exception: Transportation Revenue is calculated on Schedule 17 and Inventory Finance Charges for Nov 12 - Apr 13 calculated on Schedule 16.
2/ Credits from Repsol of $14,166.66 and BG Energy of $10,944.92 per month are included in Column (i), contracts for 11/01/2012 through 04/30/2013.

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**ENERGY NORTH NATURAL GAS, INC.**

**Peak 2012 - 2013 Winter Cost of Gas Filing**
**Demand Costs**

| | (a) | Peak (b) | Reference (c) | Peak Costs May 12 -Oct 12 (d) | Nov-12 (e) | Dec-12 (f) | Jan-13 (g) | Feb-13 (h) | Mar-13 (i) | Apr-13 (j) | Peak May -Apr Total (k) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Supply** | | | | | | | | | | | |
| | Niagra Supply | | Sch 5B, ln 9 * Sch 5C ln 9 x days | [redacted] | | | | | | | |
| | Subtotal Supply Demand & Reservation Charges | | | | | | | | | | |
| **Pipeline** | | | | | | | | | | | |
| | Iroquois Gas Trans Service RTS 470-0 | | Sch 5B, ln 12 * Sch 5C ln 12 x days | [redacted] | | | | | | | |
| | Tenn Gas Pipeline 95346 Z5-Z6 | | Sch 5B, ln 13 * Sch 5C ln 14 x days | | | | | | | | |
| | Tenn Gas Pipeline 2302 Z5-Z6 | | Sch 5B, ln 14 * Sch 5C ln 16 x days | | | | | | | | |
| | Tenn Gas Pipeline 8587 Z0-Z6 | | Sch 5B, ln 15 * Sch 5C ln 18 x days | | | | | | | | |
| | Tenn Gas Pipeline 8587 Z1-Z6 | | Sch 5B, ln 16 * Sch 5C ln 20 x days | | | | | | | | |
| | Tenn Gas Pipeline 8587 Z4-Z6 | | Sch 5B, ln 17 * Sch 5C ln 22 x days | | | | | | | | |
| | Tenn Gas Pipeline (Dracut) 42076 Z6-Z6 | | Sch 5B, ln 18 * Sch 5C ln 24 x days | | | | | | | | |
| | Tenn Gas Pipeline (Concord Lateral) Z6-Z6 | | Sch 5B, ln 19 * Sch 5C ln 26 x days | | | | | | | | |
| | Portland Natural Gas Trans Service | | Sch 5B, ln 20 * Sch 5C ln 28 x days | | | | | | | | |
| | ANE (TransCanada via Union to Iroquois) | | Sch 5B, ln 21 * Sch 5C ln 44 x days | | | | | | | | |
| | Tenn Gas Pipeline Z4-Z6 stg 632 | peak | Sch 5B, ln 22 * Sch 5C ln 30 x days | | | | | | | | |
| | Tenn Gas Pipeline Z4-Z6 stg 11234 | peak | Sch 5B, ln 23 * Sch 5C ln 32 x days | | | | | | | | |
| | Tenn Gas Pipeline Z5-Z6 stg 11234 | peak | Sch 5B, ln 24 * Sch 5C ln 34 x days | | | | | | | | |
| | National Fuel FST 2358 | peak | Sch 5B, ln 25 * Sch 5C ln 36 x days | | | | | | | | |
| | Subtotal Pipeline Demand Charges | | | $ 1,363,979 | $ 1,071,942 | $ 1,071,942 | $ 1,071,942 | $ 1,071,942 | $ 1,071,942 | $ 1,071,942 | $ 7,795,631 |
| **Peaking Supply** | | | | | | | | | | | |
| | Tenn Gas Pipeline (Concord Lateral) Z6-Z6 | peak | Sch 5B, ln 28 * Sch 5C ln 26 x days | [redacted] | | | | | | | |
| | Granite Ridge Demand | peak | Sch 5B, ln 29 * Sch 5C ln 47 x days | | | | | | | | |
| | DOMAC Demand NSB041 | peak | Per Contract | | | | | | | | |
| | Subtotal Peaking Demand Chargs | | | $ 2,026,707 | $ 316,420 | $ 441,170 | $ 441,170 | $ 441,170 | $ 441,170 | $ 316,420 | $ 4,424,227 |
| **Subtotal Supply, Pipeline & Peaking** | | | ln 13 + ln 31 + ln 37 | $ 3,390,686 | $ 1,389,418 | $ 1,514,203 | $ 1,514,203 | $ 1,514,097 | $ 1,514,203 | $ 1,389,418 | $ 12,226,227 |
| | Less Transportation Capacity Credit | | | $ (868,607) | $ (300,600) | $ (327,597) | $ (327,597) | $ (327,574) | $ (327,597) | $ (300,600) | $ (2,780,171) |
| **Total Supply, Pipeline & Peaking Demand** | | | | $ 2,522,079 | $ 1,088,818 | $ 1,186,606 | $ 1,186,606 | $ 1,186,523 | $ 1,186,606 | $ 1,088,818 | $ 9,446,057 |
| **Storage** | | | | | | | | | | | |
| | Dominion - Demand | peak | Sch 5B, ln 33 * Sch 5C ln 51 x days | $ 10,529 | $ 1,755 | $ 1,755 | $ 1,755 | $ 1,755 | $ 1,755 | $ 1,755 | $ 21,058 |
| | Dominion - Storage | peak | Sch 5B, ln 34 * Sch 5C ln 52 x days | 8,935 | 1,489 | 1,489 | 1,489 | 1,489 | 1,489 | 1,489 | 17,870 |
| | Honeoye - Demand | peak | Sch 5B, ln 35 * Sch 5C ln 55 x days | 52,466 | 8,744 | 8,744 | 8,744 | 8,744 | 8,744 | 8,744 | 104,933 |
| | National Fuel - Demand | peak | Sch 5B, ln 37 * Sch 5C ln 57 x days | 90,833 | 15,139 | 15,139 | 15,139 | 15,139 | 15,139 | 15,139 | 181,667 |
| | National Fuel - Capacity | peak | Sch 5B, ln 38 * Sch 5C ln 58 x days | 153,345 | 25,557 | 25,557 | 25,557 | 25,557 | 25,557 | 25,557 | 306,690 |
| | Tenn Gas Pipeline - Demand | peak | Sch 5B, ln 39 * Sch 5C ln 61 x days | 201,839 | 33,640 | 33,640 | 33,640 | 33,640 | 33,640 | 33,640 | 403,677 |
| | Tenn Gas Pipeline - Capacity | peak | Sch 5B, ln 40 * Sch 5C ln 62 x days | 197,546 | 32,924 | 32,924 | 32,924 | 32,924 | 32,924 | 32,924 | 395,091 |
| **Subtotal Storage Demand Costs** | | | | $ 715,492 | $ 119,249 | $ 119,249 | $ 119,249 | $ 119,249 | $ 119,249 | $ 119,249 | $ 1,430,985 |
| | Less Transportation Capacity Credit | | | $ (183,291) | $ (25,799) | $ (25,799) | $ (25,799) | $ (25,799) | $ (25,799) | $ (25,799) | $ (338,087) |
| **Total Storage Demand Costs** | | | ln 54 + ln 56 | $ 532,202 | $ 93,449 | $ 93,449 | $ 93,449 | $ 93,449 | $ 93,449 | $ 93,449 | $ 1,092,898 |
| **Total Demand Charges** | | | ln 39 + ln 54 | $ 4,106,179 | $ 1,508,666 | $ 1,633,452 | $ 1,633,452 | $ 1,633,346 | $ 1,633,452 | $ 1,508,666 | $ 13,657,212 |
| Total Transportation Capacity Credit | | | ln 41 + ln 56 | $ (1,051,898) | $ (326,399) | $ (353,396) | $ (353,396) | $ (353,373) | $ (353,396) | $ (326,399) | $ (3,118,258) |
| **Total Demand Charges less Cap. Cr.** | | | ln 60 + ln 62 | $ 3,054,281 | $ 1,182,267 | $ 1,280,055 | $ 1,280,055 | $ 1,279,973 | $ 1,280,055 | $ 1,182,267 | $ 10,538,954 |

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**ENERGY NORTH NATURAL GAS, INC.**

**Peak 2012 - 2013 Winter Cost of Gas Filing**
**Demand Volumes**

| | (a) | Peak (b) | Reference (c) | Nov-12 (d) | Dec-12 (e) | Jan-13 (f) | Feb-13 (g) | Mar-13 (h) | Apr-13 (i) |
|---|---|---|---|---|---|---|---|---|---|
| **Supply** | | | | | | | | | |
| | Niagra Supply | | | 3,199 | 3,199 | 3,199 | 3,199 | 3,199 | 3,199 |
| **Pipeline** | | | | | | | | | |
| | Iroquois Gas Trans Service | | RTS 470-01 | 4,047 | 4,047 | 4,047 | 4,047 | 4,047 | 4,047 |
| | Tenn Gas Pipeline | | 95346 Z5-Z6 | 4,000 | 4,000 | 4,000 | 4,000 | 4,000 | 4,000 |
| | Tenn Gas Pipeline | | 2302 Z5-Z6 | 3,122 | 3,122 | 3,122 | 3,122 | 3,122 | 3,122 |
| | Tenn Gas Pipeline (long haul) | | 8587 Z0-Z6 | 7,035 | 7,035 | 7,035 | 7,035 | 7,035 | 7,035 |
| | Tenn Gas Pipeline (long haul) | | 8587 Z1-Z6 | 14,561 | 14,561 | 14,561 | 14,561 | 14,561 | 14,561 |
| | Tenn Gas Pipeline (short haul) | | 8587 Z4-Z6 | 3,811 | 3,811 | 3,811 | 3,811 | 3,811 | 3,811 |
| | Tenn Gas Pipeline | | 42076 FTA Z6-Z6 | 20,000 | 20,000 | 20,000 | 20,000 | 20,000 | 20,000 |
| | Tenn Gas Pipeline (Concord Lateral) | | 72694 Z6-Z6 | 4,000 | 4,000 | 4,000 | 4,000 | 4,000 | 4,000 |
| | Portland Natural Gas Trans Service | | FT-1999-001 | 1,000 | 1,000 | 1,000 | 1,000 | 1,000 | 1,000 |
| | ANE (TransCanada via Union to Iroquois) | | Union Parkway to Iroquois | 4,047 | 4,047 | 4,047 | 4,047 | 4,047 | 4,047 |
| | Tenn Gas Pipeline (short haul) | peak | 632 Z4-Z6 (stg) | 15,265 | 15,265 | 15,265 | 15,265 | 15,265 | 15,265 |
| | Tenn Gas Pipeline (short haul) | peak | 11234 Z4-Z6(stg) | 7,082 | 7,082 | 7,082 | 7,082 | 7,082 | 7,082 |
| | Tenn Gas Pipeline (short haul) | peak | 11234 Z5-Z6(stg) | 1,957 | 1,957 | 1,957 | 1,957 | 1,957 | 1,957 |
| | National Fuel | peak | FST 2358 | 6,098 | 6,098 | 6,098 | 6,098 | 6,098 | 6,098 |
| **Peaking** | | | | | | | | | |
| | Tenn Gas Pipeline (Concord Lateral) | peak | | 26,000 | 26,000 | 26,000 | 26,000 | 26,000 | 26,000 |
| | Granite Ridge Demand | peak | | 0 | 0 | 0 | 0 | 0 | 0 |
| | DOMAC Liquid Demand Charge | peak | NSB041 | 0 | 2,850 | 2,850 | 2,850 | 2,850 | 0 |
| **Storage** | | | | | | | | | |
| | Dominion - Demand | peak | GSS 300076 | 934 | 934 | 934 | 934 | 934 | 934 |
| | Dominion - Capacity Reservation | peak | GSS 300076 | 102,700 | 102,700 | 102,700 | 102,700 | 102,700 | 102,700 |
| | Honeoye - Demand | peak | SS-NY | 1,362 | 1,362 | 1,362 | 1,362 | 1,362 | 1,362 |
| | Honeoye - Capacity | peak | SS-NY | 246,240 | 246,240 | 246,240 | 246,240 | 246,240 | 246,240 |
| | National Fuel - Demand | peak | FSS-1 2357 | 6,098 | 6,098 | 6,098 | 6,098 | 6,098 | 6,098 |
| | National Fuel - Capacity Reservation | peak | FSS-1 2357 | 670,800 | 670,800 | 670,800 | 670,800 | 670,800 | 670,800 |
| | Tenn Gas Pipeline - Demand | peak | FS-MA | 21,844 | 21,844 | 21,844 | 21,844 | 21,844 | 21,844 |
| | Tenn Gas Pipeline - Cap. Reservations | peak | FS-MA | 1,560,391 | 1,560,391 | 1,560,391 | 1,560,391 | 1,560,391 | 1,560,391 |

**ENERGY NORTH NATURAL GAS, INC.**

**Peak 2012 - 2013 Winter Cost of Gas Filing**
**Demand Rates**

| | | | | | Nov-12 | Dec-12 | Jan-13 | Feb-13 | Mar-13 | Apr-13 | Nov - Apr |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Tariff Rates** | | | | | 30 | 31 | 31 | 28 | 31 | 30 | 181 |
| | | | | | Unit Rate | Unit Rate | Unit Rate | Unit Rate | Unit Rate | Unit Rate | Avg Rate |
| **Supply** | | | | | | | | | | | |
| Niagra Supply | [redacted] | | | | | | | | | | |
| **Pipeline** | | | | | | | | | | | |
| Iroquois Gas Trans Service | RTS 470-01 | $6.5971 | First Revised Sheet No. 4 | | $0.2199 | $0.2128 | $0.2128 | $0.2356 | $0.2128 | $0.2199 | $0.2190 |
| Tenn Gas Pipeline | 95346 Z5-Z6 | $7.4396 | Fifth Rev Sheet No.14 | | $0.2480 | $0.2400 | $0.2400 | $0.2657 | $0.2400 | $0.2480 | $0.2469 |
| Tenn Gas Pipeline | 2302 Z5-Z6 | $7.4396 | Fifth Rev Sheet No.14 | | $0.2480 | $0.2400 | $0.2400 | $0.2657 | $0.2400 | $0.2480 | $0.2469 |
| Tenn Gas Pipeline | 8587 Z0-Z6 | $24.4547 | Fifth Rev Sheet No.14 | | $0.8152 | $0.7889 | $0.7889 | $0.8734 | $0.7889 | $0.8152 | $0.8117 |
| Tenn Gas Pipeline | 8587 Z1-Z6 | $21.6916 | Fifth Rev Sheet No.14 | | $0.7231 | $0.6997 | $0.6997 | $0.7747 | $0.6997 | $0.7231 | $0.7200 |
| Tenn Gas Pipeline | 8587 Z4-Z6 | $8.4896 | Fifth Rev Sheet No.14 | | $0.2830 | $0.2739 | $0.2739 | $0.3032 | $0.2739 | $0.2830 | $0.2818 |
| TGP Dracut | 42076 FTA Z6-Z6 | $4.8846 | Fifth Rev Sheet No.14 | | $0.1628 | $0.1576 | $0.1576 | $0.1745 | $0.1576 | $0.1628 | $0.1621 |
| TGP Concord Lateral | 72694 Z6-Z6 | $12.1700 | Per contract | | $0.4057 | $0.3926 | $0.3926 | $0.4346 | $0.3926 | $0.4057 | $0.4040 |
| Portland Natural Gas | FT-1999-001 | $40.2456 | Part 4.1 v.3.0.0 | | $1.3415 | $1.2982 | $1.2982 | $1.4373 | $1.2982 | $1.3415 | $1.3359 |
| Tenn Gas Pipeline | 632 Z4-Z6 (stg) | $8.4896 | Fifth Rev Sheet No.14 | | $0.2830 | $0.2739 | $0.2739 | $0.3032 | $0.2739 | $0.2830 | $0.2818 |
| Tenn Gas Pipeline | 11234 Z4-Z6(stg) | $8.4896 | Fifth Rev Sheet No.14 | | $0.2830 | $0.2739 | $0.2739 | $0.3032 | $0.2739 | $0.2830 | $0.2818 |
| Tenn Gas Pipeline | 11234 Z5-Z6(stg) | $7.4396 | Fifth Rev Sheet No.14 | | $0.2480 | $0.2400 | $0.2400 | $0.2657 | $0.2400 | $0.2480 | $0.2469 |
| National Fuel | FST 2358 | $3.7805 | 4.010 Version 4.0.0 Pg 1 | | $0.1260 | $0.1220 | $0.1220 | $0.1350 | $0.1220 | $0.1260 | $0.1255 |
| ANE Union Gas | | $2.3117 | | | | | | | | | |
| TransCanada PipeLines Limited | | $10.1678 | Union Parkway to Iroquois | | | | | | | | |
| Delivery Pressure Demand Charge | | 1.0379 | Union Parkway to Iroquois | | | | | | | | |
| Sub Total Demand Charges | | 13.5173 | | | | | | | | | |
| Conversion rate GJ to MMBTU | | 1.0551 | | | | | | | | | |
| Conversion rate to US$ | | 0.9940 | 07/27/2012 | | | | | | | | |
| Demand Rate/US$ | | $14.3482 | | | $0.4783 | $0.4628 | $0.4628 | $0.5124 | $0.4628 | $0.4783 | $0.4763 |
| **Peaking** | | | | | | | | | | | |
| Granite Ridge Demand | [redacted] | | | | | | | | | | |
| DOMAC Demand NSB041 | | | | | | | | | | | |
| **Storage** | | | | | | | | | | | |
| Dominion - Demand | GSS 300076 | $1.8788 | Rec No 10.30 Ver 5.0.0 | | $0.0626 | $0.0606 | $0.0606 | $0.0671 | $0.0606 | $0.0626 | $0.0623 |
| Dominion - Capacity | GSS 300076 | $0.0145 | Rec No 10.30 Ver 5.0.0 | | $0.0005 | $0.0005 | $0.0005 | $0.0005 | $0.0005 | $0.0005 | $0.0005 |
| | | $1.8933 | | | $0.0631 | $0.0611 | $0.0611 | $0.0676 | $0.0611 | $0.0631 | $0.0628 |
| Honeoye - Demand | SS-NY | $6.4187 | Sub 1st Rev Sheet No. 5 | | $0.2140 | $0.2071 | $0.2071 | $0.2292 | $0.2071 | $0.2140 | $0.2129 |
| National Fuel - Demand | FSS-1 2357 | $2.4826 | 4.020 Version 3.0.2 Pg 1 | | $0.0828 | $0.0801 | $0.0801 | $0.0887 | $0.0801 | $0.0828 | $0.0823 |
| National Fuel - Capacity | FSS-1 2357 | $0.0381 | 4.020 Version 3.0.2 Pg 1 | | $0.0013 | $0.0012 | $0.0012 | $0.0014 | $0.0012 | $0.0013 | $0.0013 |
| | | $2.5207 | | | $0.0840 | $0.0813 | $0.0813 | $0.0900 | $0.0813 | $0.0840 | $0.0836 |
| Tenn Gas Pipeline | FS-MA | $1.5400 | Seventh Rev Sheet No.61 | | $0.0513 | $0.0497 | $0.0497 | $0.0550 | $0.0497 | $0.0513 | $0.0511 |
| Tenn Gas Pipeline - Space | FS-MA | $0.0211 | Seventh Rev Sheet No.61 | | $0.0007 | $0.0007 | $0.0007 | $0.0008 | $0.0007 | $0.0007 | $0.0007 |
| | | $1.5611 | | | $0.0520 | $0.0504 | $0.0504 | $0.0558 | $0.0504 | $0.0520 | $0.0518 |

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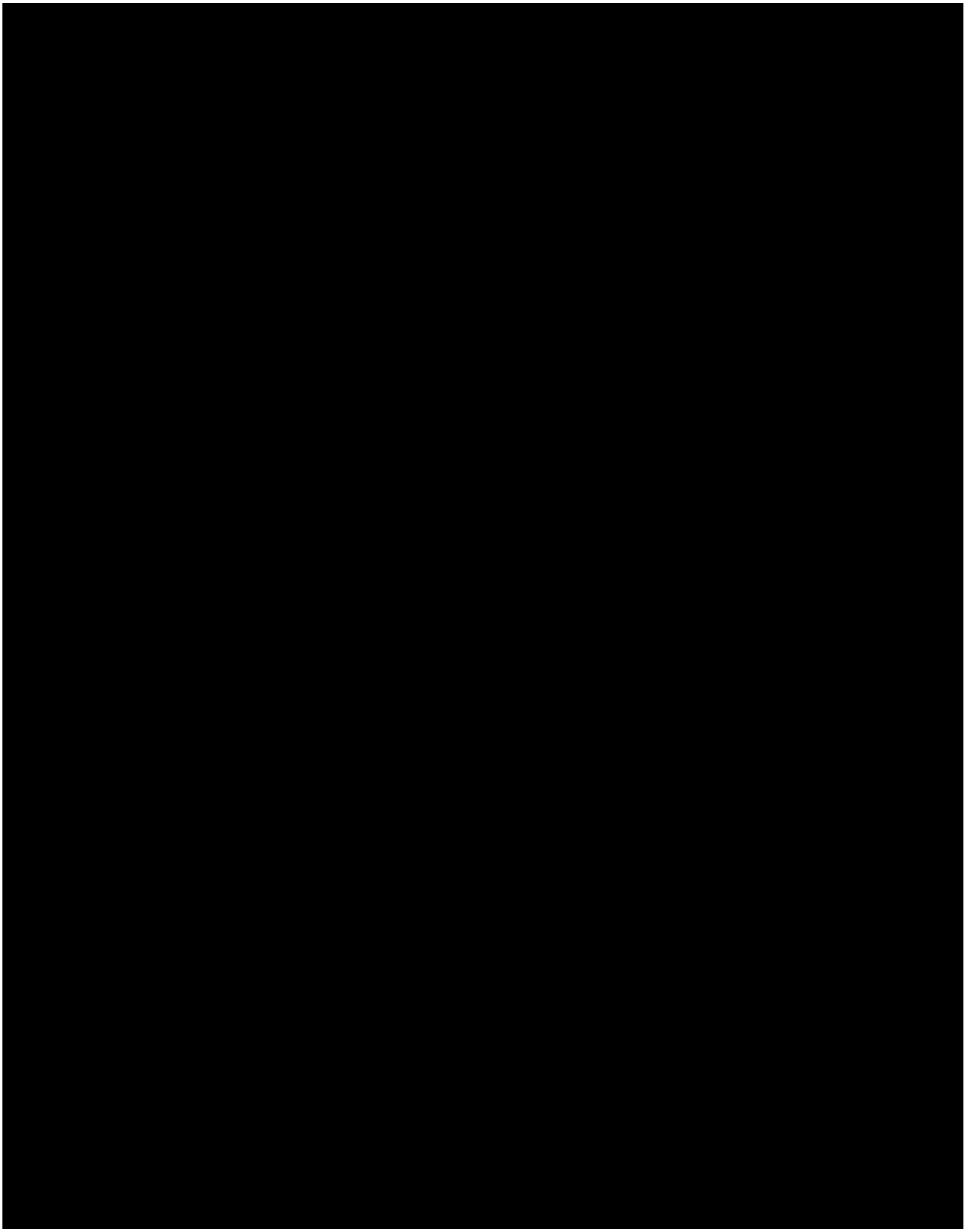

APPLICABLE TO SETTLING PARTIES PURSUANT TO THE MARCH 29, 2005, STIPULATION
IN DOCKET NOS. RP97-406, RP00-15, RP00-344 and RP00-632
(FOR RATES APPLICABLE TO SEVERED PARTIES IN THE ABOVE REFERENCED DOCKETS SEE TARIFF RECORD 10.31)
RATES APPLICABLE TO RATE SCHEDULES IN
FERC GAS TARIFF, VOLUME NO. 1
($ per DT)

| Rate Schedule (1) | Rate Component (2) | Base Tariff Rate [1] (3) | Current Acct 858 Base (4) | Current EPCA Base (5) | TCRA [5] Surcharge (6) | EPCA [6] Surcharge (7) | FERC ACA (8) | Current Rate (9) |
|---|---|---|---|---|---|---|---|---|
| GSS [2], [4] | | | | | | | | |
| | Storage Demand | $1.7984 | $0.0664 | $0.0255 | ($0.0054) | $0.0043 | - | $1.8892 |
| | Storage Capacity | $0.0145 | - | - | - | - | - | $0.0145 |
| | Injection Charge | $0.0154 | - | $0.0081 | $0.0001 | $0.0006 | - | $0.0242 |
| | Withdrawal Charge | $0.0154 | - | - | $0.0001 | $0.0006 | $0.0019 | $0.0180 |
| | GSS-TE Surcharge [3] | - | $0.0046 | - | $0.0007 | - | - | $0.0053 |
| | Demand Charge Adjustment | $21.5808 | $0.7968 | $0.3060 | ($0.0648) | $0.0516 | - | $22.6704 |
| | From Customers Balance | $0.6163 | $0.0147 | $0.0056 | ($0.0011) | $0.0016 | $0.0019 | $0.6390 |
| GSS-E [2], [4] | | | | | | | | |
| | Storage Demand | $2.2113 | $0.0664 | $0.0255 | ($0.0054) | $0.0043 | - | $2.3021 |
| | Storage Capacity | $0.0369 | - | - | - | - | - | $0.0369 |
| | Injection Charge | $0.0154 | - | $0.0081 | $0.0001 | $0.0006 | - | $0.0242 |
| | Withdrawal Charge | $0.0154 | - | - | $0.0001 | $0.0006 | $0.0019 | $0.0180 |
| | Authorized Overruns | $1.0657 | $0.0147 | $0.0056 | ($0.0011) | $0.0016 | $0.0019 | $1.0884 |
| ISS [2] | | | | | | | | |
| | ISS Capacity | $0.0736 | $0.0022 | $0.0008 | ($0.0002) | $0.0001 | - | $0.0765 |
| | Injection Charge | $0.0154 | - | $0.0081 | $0.0001 | $0.0006 | - | $0.0242 |
| | Withdrawal Charge | $0.0154 | - | - | $0.0001 | $0.0006 | $0.0019 | $0.0180 |
| | Authorized Overrun/from Cust. Bal | $0.6163 | $0.0147 | $0.0056 | ($0.0011) | $0.0016 | $0.0019 | $0.6390 |
| | Excess Injection Charge | $0.2245 | - | $0.0081 | $0.0001 | $0.0006 | - | $0.2333 |

[1] The base tariff rate is the effective rate on file with the FERC, excluding adjustments approved by the Commission.
[2] Storage Service Fuel Retention Percentage is 2.28% plus Adders of 0.28% (RP00-632 S&A approved 9/13/01) totaling 2.56%.
[3] Applies to withdrawals made under Rate Schedule GSS, Section 5.1.G.
[4] Daily Capacity Release Rate for GSS per Dt is $0.6210. Daily Capacity Release Rate for GSS-E per Dt is $1.0704.
[5] 858 over/under from previous TCRA period.
[6] Electric over/under from previous EPCA period.

subject to an allowable variation of not more than one percent above or below the aggregate of said scheduled daily deliveries of said month.

The amount of gas in storage for Buyer's account at any time (exclusive of Buyer's share of cushion gas) shall be Buyer's Gas Storage Balance at that time and shall not exceed Buyer's Maximum Quantity Stored (MQS).

Seller shall be ready at all times to deliver to Buyer, and Buyer shall have the right at all times to receive from Seller, natural gas up to the MDWQ Seller is obligated to deliver to Buyer on that day.

Buyer's MQS, Buyer's MDWQ and Buyer's ADWQ shall be specified in the Gas Storage Agreement providing for service under this Rate Schedule.

3. RATE

Buyer shall pay Seller for each month of the year during the term of the Gas Storage Agreement a Demand Charge which shall be six dollars and forty one point eight seven cents per MMBTU ($6.4187/MMBTU)** multiplied by the ADWQ as provided for in the Gas Storage Agreement.

4. MINIMUM BILL

The Minimum Bill for each month shall consist of the Demand Charge for the ADWQ as defined in Article 3.

5. COMPRESSOR FUEL ALLOWANCE

Buyer will make available without charge to Seller such additional quantities of gas as needed by Seller for

** The Demand Charge Rate set forth in individual service agreements shall be deemed to have been converted to a thermal billing basis utilizing a factor of 1022/MMBTU per 1 MCF as adjusted pursuant to Section III of the General Terms & Conditions, provided however, the total Maximum Quantity Stored in the field shall not exceed 4.8 BCF and provided that each Buyer shall receive its allowable share of same.

| | RATES (All in $ Per Dth) | | | | | | |
|---|---|---|---|---|---|---|---|
| | | Non-Settlement Recourse & Eastchester | Settlement Recourse Rates — Applicable to Non-Eastchester/Non-Contesting Shippers 2/ | | | | |
| | Minimum | Initial Rates 3/ | Effective 1/1/2003 | Effective 7/1/2004 | Effective 1/1/2005 | Effective 1/1/2006 | Effective 1/1/2007 |
| RTS DEMAND: | | | | | | | |
| Zone 1 | $0.0000 | $7.5637 | $7.5637 | $6.9586 | $6.8514 | $6.7788 | $6.5971 |
| Zone 2 | $0.0000 | $6.4976 | $6.4976 | $5.9778 | $5.8857 | $5.8233 | $5.6673 |
| Inter-Zone | $0.0000 | $12.7150 | $12.7150 | $11.6978 | $11.5177 | $11.3956 | $11.0902 |
| Zone 1 (MFV) 1/ | $0.0000 | $5.3607 | $5.3607 | $4.9318 | $4.8559 | $4.8044 | $4.6757 |
| RTS COMMODITY: | | | | | | | |
| Zone 1 | $0.0030 | $0.0030 | $0.0030 | $0.0030 | $0.0030 | $0.0030 | $0.0030 |
| Zone 2 | $0.0024 | $0.0024 | $0.0024 | $0.0024 | $0.0024 | $0.0024 | $0.0024 |
| Inter-Zone | $0.0054 | $0.0054 | $0.0054 | $0.0054 | $0.0054 | $0.0054 | $0.0054 |
| Zone 1 (MFV) 1/ | $0.0300 | $0.1506 | $0.1506 | $0.1386 | $0.1364 | $0.1350 | $0.1314 |
| ITS COMMODITY: | | | | | | | |
| Zone 1 | $0.0030 | $0.2517 | $0.2517 | $0.2318 | $0.2283 | $0.2259 | $0.2199 |
| Zone 2 | $0.0024 | $0.2160 | $0.2160 | $0.1989 | $0.1959 | $0.1938 | $0.1887 |
| Inter-Zone | $0.0054 | $0.4234 | $0.4234 | $0.3900 | $0.3840 | $0.3800 | $0.3700 |
| Zone 1 (MFV) 1/ | $0.0300 | $0.3268 | $0.3268 | $0.3007 | $0.2960 | $0.2929 | $0.2850 |
| MAXIMUM VOLUMETRIC CAPACITY RELEASE RATE 4/: | | | | | | | |
| Zone 1 | $0.0000 | $0.2487 | $0.2487 | $0.2288 | $0.2253 | $0.2229 | $0.2169 |
| Zone 2 | $0.0000 | $0.2136 | $0.2136 | $0.1965 | $0.1935 | $0.1915 | $0.1863 |
| Inter-Zone | $0.0000 | $0.4180 | $0.4180 | $0.3846 | $0.3787 | $0.3746 | $0.3646 |
| Zone 1 (MFV) 1/ | $0.0000 | $0.1762 | $0.1762 | $0.1621 | $0.1596 | $0.1580 | $0.1537 |

**SEE SHEET NO. 4A FOR ADJUSTMENTS TO RATES WHICH MAY BE APPLICABLE

(Footnotes continued on Sheet 4.01)

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1/ As authorized pursuant to order of the Federal Energy Regulatory Commission, Docket Nos. RS92-17-003, et al., dated June 18, 1993 (63 FERC para. 61,285).

2/ Settlement Recourse Rates were established in Iroquois' Settlement dated August 29, 2003, which was approved by Commission order issued Oct. 24, 2003, in Docket No. RP03-589-000. That Settlement also established a moratorium on changes to the Settlement Rates until January 1, 2008, defines the Non-Eastchester/Non-Contesting parties to which it applies, and provides that Iroquois' TCRA will be terminated on July 1, 2004.

3/ See Sections 1.2 and 4.3 of the Settlement referenced in footnote 2. As directed by the Commission's January 30, 2004 Order in Docket No. RP04-136, the Eastchester Initial Rates apply for service to Eastchester Shippers prior to the July 1, 2004 effective date of the rates set forth on Sheet No. 4C.

4/ No rate cap shall apply to any capacity releases with terms of less than or equal to one year pursuant to FERC Order Nos. 712 et al.

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**RATES FOR TRANSPORTATION SERVICES***

| Rate Sch. (1) | Rate Component 1/ (2) | | Base Rate (3) | TSCA (4) | TSCA Surch. (5) | FERC ACA (6) | Current Rate 2/ (7) |
|---|---|---|---|---|---|---|---|
| FT/FT-S | | | | | | | |
| | Reservation | (Max) | $3.7805 | - | - | - | $ 3.7805 |
| | | (Min) | 0.0000 | - | - | - | $0.0000 |
| | Commodity | (Max) | 0.0135 | - | - | 0.0018 | $0.0153 |
| | | (Min) | 0.0135 | - | - | 0.0018 | $0.0153 |
| | Overrun | (Max) | 0.1378 | - | - | 0.0018 | $0.1396 |
| | | (Min) | 0.0135 | - | - | 0.0018 | $0.0153 |
| | Maximum Volumetric Rate | | 0.1378 | - | - | 0.0018 | $0.1396 |
| EFT | Reservation | (Max) | 3.9653 | 0.0000 | (0.0036) | - | $3.9617 |
| | | (Min) | 0.0000 | 0.0000 | (0.0036) | - | $(0.0036) |
| | Commodity | (Max) | 0.0148 | 0.0000 | 0.0000 | 0.0018 | $0.0166 |
| | | (Min) | 0.0148 | 0.0000 | 0.0000 | 0.0018 | $0.0166 |
| | Overrun | (Max) | 0.1452 | - | - | 0.0018 | $0.1470 |
| | | (Min) | 0.0148 | - | - | 0.0018 | $0.0166 |
| | Maximum Volumetric Rate | | 0.1452 | 0.0000 | (0.0001) | 0.0018 | $0.1469 |
| FST | Reservation | (Max) | 3.7805 | - | - | | $ 3.7805 |
| | | (Min) | 0.0000 | - | - | | $0.0000 |
| | Commodity | (Max) | 0.0135 | - | - | 0.0018 | $0.0153 |
| | | (Min) | 0.0135 | - | - | 0.0018 | $0.0153 |
| | Overrun | (Max) | 0.1378 | - | - | 0.0018 | $0.1396 |
| | | (Min) | 0.0135 | - | - | 0.0018 | $0.0153 |
| | Maximum Volumetric Rate | | 0.1378 | - | - | 0.0018 | $0.1396 |
| IT | Commodity | (Max) | $0.1378 | - | - | 0.0018 | $ 0.1396 |
| | | (Min) | 0.0000 | - | - | 0.0018 | $0.0018 |
| | Overrun | (Max) | 0.1378 | - | | 0.0018 | $0.1396 |
| | | (Min) | 0.0000 | - | - | 0.0018 | $0.0018 |

*The rates and retention factors set forth in this section are subject to surcharge or direct bill under the conditions set forth in the order of the Chief Administrative Law Judge in Docket No. RP12-88 granting Transporter's motion to place settlement rates into effect on an interim basis. Gathering rates applicable to Transporter's transportation services are set forth in Section 4.040.

1/ The unit of measure for each rate component is the Dth unless otherwise indicated.

2/ All rates exclusive of Fuel and Company Use retention and Transportation LAUF retention. Fuel and Company Use retention for all applicable rate schedules is 1.15%. Transportation LAUF retention for all applicable rate schedules is 0.25%. Provided, however, that effective as of (i) the first day of the month following an order by the Chief Administrative Law Judge accepting this tariff record issued at least five (5) business days prior to the end of a calendar month or (ii) the first day of the second month following an order by the Chief Administrative Law Judge accepting this tariff record issued within the last five (5) business days of a calendar month, the Fuel and Company Use retention for all applicable rate schedules is 0.71% and the Transportation LAUF retention for all applicable rate schedules is 0.05%. Transporter may from time to time identify point pair transactions where the Fuel and Company Use retention shall be zero ("Zero Fuel Point Pair Transactions"). Zero Fuel Point Pair Transactions will be assessed the applicable Transportation LAUF retention.

**RATES FOR PART 284 STORAGE SERVICES***

| Rate Sch. (1) | Rate Component 1/ (2) | | Base Rate (3) | FERC ACA (4) | Current Rate 2/ (5) |
|---|---|---|---|---|---|
| ESS | Demand | (Max) | $2.5959 | - | $ 2.5959 |
| | | (Min) | 0.0000 | - | $0.0000 |
| | Capacity | (Max) | 0.0404 | - | $0.0404 |
| | | (Min) | 0.0000 | - | $0.0000 |
| | Injection/ | (Max) | 0.0411 | 0.0018 | $0.0429 |
| | Withdrawal | (Min) | 0.0000 | - | $0.0000 |
| | Max. Volumetric Dem. Rate 4/ | | 0.0853 | 0.0018 | $0.0871 |
| | Max. Volumetric Cap. Rate 5/ | | 0.0013 | - | $0.0013 |
| | Storage Balance Transfer | (Max) 6/ | 3.8600 | - | $3.8600 |
| | | (Min) 6/ | 0.0000 | - | $0.0000 |
| ISS | Injection | (Max) | 0.9923 | 0.0018 | $0.9941 |
| | | (Min) | 0.0000 | - | $0.0000 |
| | Storage Balance Transfer | (Max) 6/ | 3.8600 | - | $3.8600 |
| | | (Min) 6/ | 0.0000 | - | $0.0000 |
| FSS | Demand | (Max) | 2.4826 | - | $ 2.4826 |
| | | (Min) | 0.0000 | - | $0.0000 |
| | Capacity | (Max) | 0.0381 | - | $0.0381 |
| | | (Min) | 0.0000 | - | $0.0000 |
| | Injection/ | (Max) | 0.0391 | 0.0018 | $0.0409 |
| | Withdrawal | (Min) | 0.0000 | - | $0.0000 |
| | Max. Volumetric Dem. Rate 4/ | | 0.0816 | 0.0018 | $0.0834 |
| | Max. Volumetric Cap. Rate 5/ | | 0.0013 | - | $ 0.0013 |
| | Storage Balance Transfer | (Max) 6/ | 3.8600 | - | $3.8600 |
| | | (Min) 6/ | 0.0000 | - | $0.0000 |

* The rates and retention factors set forth in this section are subject to surcharge or direct bill under the conditions set forth in the order of the Chief Administrative Law Judge in Docket No. RP12-88 granting Transporter's motion to place settlement rates into effect on an interim basis.

1/ The unit of measure for each rate component is the Dth unless otherwise indicated.

2/ All rates exclusive of Surface Operating Allowance and Storage LAUF retention, where applicable. Surface Operating Allowance for all applicable rate schedules is 1.17%. Storage LAUF retention for all applicable rate schedules is 0.23%. Provided, however, that effective as of (i) the first day of the month following an order by the Chief Administrative Law Judge issued at least five (5) business days prior to the end of a calendar month accepting this tariff record or (ii) the first day of the second month following an order by the Chief Administrative Law Judge issued within the last five (5) business days of a calendar month, the Surface Operating Allowance for all applicable rate schedules is 1.20% and the Storage LAUF retention for all applicable rate schedules is 0.11%.

3/ Unit Dth Rates per day.

4/ Assessed per dekatherm injected/withdrawn. Exclusive of Injection/Withdrawal charge.

5/ Assessed per dekatherm per day on storage balance.

6/ Rate per nomination.

Statement of Transportation Rates
(Rates per DTH)

| Rate Schedule | Rate Component | Base Rate | ACA Unit Charge 1/ | Current Rate |
|---|---|---|---|---|
| FT | Recourse Reservation Rate | | | |
| | -- Maximum | $40.2456 | --------- | $40.2456 |
| | -- Minimum | $00.0000 | --------- | $00.0000 |
| | Seasonal Recourse Reservation Rate | | | |
| | -- Maximum | $76.4666 | --------- | $76.4666 |
| | -- Minimum | $00.0000 | --------- | $00.0000 |
| | Recourse Usage Rate | | | |
| | -- Maximum | $00.0000 | $00.0018 | $00.0018 |
| | -- Minimum | $00.0000 | $00.0018 | $00.0018 |
| FT-FLEX | Recourse Reservation Rate | | | |
| | --Maximum | $27.0128 | --------- | $27.0128 |
| | --Minimum | $00.0000 | --------- | $00.0000 |
| | Recourse Usage Rate | | | |
| | --Maximum | $00.4350 | $00.0018 | $00.4369 |
| | --Minimum | $00.0000 | $00.0018 | $00.0018 |

The following adjustment applies to all Rate Schedules above:

MEASUREMENT VARIANCE:

Minimum down to -1.00%
Maximum up to +1.00%

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1/ ACA assessed where applicable under Section 154.402 of the Commission's regulations and will be charged pursuant to Section 6.18 of the General Terms and Conditions at such time that initial and successive ACA assessments are made.

RATES PER DEKATHERM

FIRM TRANSPORTATION RATES
RATE SCHEDULE FOR FT-A

Base Reservation Rates

| RECEIPT ZONE | DELIVERY ZONE 0 | L | 1 | 2 | 3 | 4 | 5 | 6 |
|---|---|---|---|---|---|---|---|---|
| 0 | $5.7504 | | $12.1229 | $16.3405 | $16.6314 | $18.3503 | $19.4843 | $24.4547 |
| L | | $5.0941 | | | | | | |
| 1 | $8.7060 | | $8.3414 | $11.1329 | $15.8114 | $15.6260 | $17.6356 | $21.6916 |
| 2 | $16.3406 | | $11.0654 | $5.7084 | $5.3300 | $6.8689 | $9.4859 | $12.2575 |
| 3 | $16.6314 | | $8.7447 | $5.7553 | $4.1249 | $6.4085 | $11.6731 | $13.4872 |
| 4 | $21.1425 | | $19.4839 | $7.3648 | $11.2429 | $5.4700 | $5.9240 | $8.4896 |
| 5 | $25.2282 | | $17.6984 | $7.7303 | $9.3742 | $6.0880 | $5.7043 | $7.4396 |
| 6 | $29.1846 | | $20.3275 | $13.9551 | $15.3850 | $10.8692 | $5.6613 | $4.8846 |

Daily Base Reservation Rate 1/

| RECEIPT ZONE | DELIVERY ZONE 0 | L | 1 | 2 | 3 | 4 | 5 | 6 |
|---|---|---|---|---|---|---|---|---|
| 0 | $0.1891 | | $0.3986 | $0.5372 | $0.5468 | $0.6033 | $0.6406 | $0.8040 |
| L | | $0.1675 | | | | | | |
| 1 | $0.2862 | | $0.2742 | $0.3660 | $0.5198 | $0.5137 | $0.5798 | $0.7131 |
| 2 | $0.5372 | | $0.3638 | $0.1877 | $0.1752 | $0.2258 | $0.3119 | $0.4030 |
| 3 | $0.5468 | | $0.2875 | $0.1892 | $0.1356 | $0.2107 | $0.3838 | $0.4434 |
| 4 | $0.6951 | | $0.6406 | $0.2421 | $0.3696 | $0.1798 | $0.1948 | $0.2791 |
| 5 | $0.8294 | | $0.5819 | $0.2541 | $0.3082 | $0.2002 | $0.1875 | $0.2446 |
| 6 | $0.9595 | | $0.6683 | $0.4588 | $0.5058 | $0.3573 | $0.1861 | $0.1606 |

Maximum Reservation Rates 2 /, 3 /

| RECEIPT ZONE | DELIVERY ZONE 0 | L | 1 | 2 | 3 | 4 | 5 | 6 |
|---|---|---|---|---|---|---|---|---|
| 0 | $5.7504 | | $12.1229 | $16.3405 | $16.6314 | $18.3503 | $19.4843 | $24.4547 |
| L | | $5.0941 | | | | | | |
| 1 | $8.7060 | | $8.3414 | $11.1329 | $15.8114 | $15.6260 | $17.6356 | $21.6916 |
| 2 | $16.3406 | | $11.0654 | $5.7084 | $5.3300 | $6.8689 | $9.4859 | $12.2575 |
| 3 | $16.6314 | | $8.7447 | $5.7553 | $4.1249 | $6.4085 | $11.6731 | $13.4872 |
| 4 | $21.1425 | | $19.4839 | $7.3648 | $11.2429 | $5.4700 | $5.9240 | $8.4896 |
| 5 | $25.2282 | | $17.6984 | $7.7303 | $9.3742 | $6.0880 | $5.7043 | $7.4396 |
| 6 | $29.1846 | | $20.3275 | $13.9551 | $15.3850 | $10.8692 | $5.6613 | $4.8846 |

Notes:
1/ Applicable to demand charge credits and secondary points under discounted rate agreements.
2/ Includes a per Dth charge for the PCB Surcharge Adjustment per Article XXXII of the General Terms and Conditions of $0.0000.
3/ Includes a per Dth charge for the PS/GHG Surcharge Adjustment per Article XXXVIII of the General Terms and Conditions of $0.0000.

RATE SCHEDULE NET 284 1/, 2/

Notes:

1/ The rates for service under Rate Schedule NET-284 shall be equal to the applicable rates for service under Rate Schedule FT-A in the Summary of Rates and Charges on Sheet Nos. 14 – 17.

2/ The applicable F&LR's and EPCR's, determined pursuant to Article XXXVII of the General Terms and Conditions, are listed on Sheet No. 32. For service rendered entirely by displacement and for gas scheduled and allocated for receipt at the Dracut, Massachusetts receipt point, Shipper shall render only the quantity of gas associated with Losses of 0.21%.

RATES PER DEKATHERM

FIRM STORAGE SERVICE
RATE SCHEDULE FS

| Rate Schedule and Rate | Base Tariff Rate | Max Tariff Rate | F&LR 2/, 3/ | EPCR 2/ |
|---|---|---|---|---|
| FIRM STORAGE SERVICE (FS) - PRODUCTION AREA | | | | |
| Deliverability Rate | $2.8100 | $2.8100 1/ | | |
| Space Rate | $0.0286 | $0.0286 1/ | | |
| Injection Rate | $0.0073 | $0.0073 | 1.91% | $0.0000 |
| Withdrawal Rate | $0.0073 | $0.0073 | | |
| Overrun Rate | $0.3372 | $0.3372 1/ | | |
| FIRM STORAGE SERVICE (FS) - MARKET AREA | | | | |
| Deliverability Rate | $1.5400 | $1.5400 1/ | | |
| Space Rate | $0.0211 | $0.0211 1/ | | |
| Injection Rate | $0.0087 | $0.0087 | 1.91% | $0.0000 |
| Withdrawal Rate | $0.0087 | $0.0087 | | |
| Overrun Rate | $0.1848 | $0.1848 1/ | | |

1/ Includes a per Dth charge for the PCB Surcharge Adjustment per Article XXXII of the General Terms and Conditions of $0.000.
2/ The F&LR's and EPCR's determined pursuant to Article XXXVII of the General Terms and Conditions.
3/ The applicable F&LR pursuant to Article XXXVII of the General Terms and Conditions, associated with Losses is equal to 0.21%.

TRANSPORTATION RATES

**(A) Applicability**

The charges under this schedule shall be applicable to a Shipper who enters into a Transportation Service Contract with Union.

**(B) Services**

Transportation Service under this rate schedule shall be for transportation on Union's Dawn - Oakville facilities.

**(C) Rates**

The identified rates represent maximum prices for service. These rates may change periodically. Multi-year prices may also be negotiated, which may be higher than the identified rates.

| | Monthly Demand Charge (applied to daily contract demand) Rate/GJ | Commodity and Fuel Charges Fuel Ratio % | AND | Commodity Charge Rate/GJ |
|---|---|---|---|---|
| **Firm Transportation (1)** | | | | |
| Dawn to Oakville/Parkway | $2.323 | | | |
| Dawn to Kirkwall | $1.978 | Monthly fuel rates and ratios shall be in | | |
| Kirkwall to Parkway | $0.345 | accordance with schedule "C". | | |
| Parkway to Dawn | n/a | | | |
| **M12-X Firm Transportation** | | | | |
| Between Dawn, Kirkwall and Parkway | $2.868 | Monthly fuel rates and ratios shall be in accordance with schedule "C". | | |
| **Limited Firm/Interruptible Transportation (1)** | | | | |
| Dawn to Parkway – Maximum | $5.576 | Monthly fuel rates and ratios shall be in | | |
| Dawn to Kirkwall – Maximum | $5.576 | accordance with schedule "C". | | |
| Parkway (TCPL) to Parkway (Cons) (2) | | 0.328% | | |

**Authorized Overrun (3)**

Authorized overrun rates will be payable on all quantities in excess of Union's obligation on any day. The overrun charges payable will be calculated at the following rates. Overrun will be authorized at Union's sole discretion.

| Transportation Overrun | If Union supplies fuel Commodity Charge Rate/GJ | Commodity and Fuel Charges Fuel Ratio % | AND | Commodity Charge Rate/GJ |
|---|---|---|---|---|
| Dawn to Parkway | | | | $0.076 |
| Dawn to Kirkwall | | Monthly fuel rates and ratios shall be in | | $0.065 |
| Kirkwall to Parkway | | accordance with schedule "C". | | $0.011 |
| Parkway to Dawn | | | | $0.076 |
| Parkway (TCPL) Overrun (4) | n/a | 0.256% | | n/a |
| M12-X Firm Transportation | | | | |
| Between Dawn, Kirkwall and Parkway | | Monthly fuel rates and ratios shall be in accordance with schedule "C". | | $0.094 |

Transportation Tolls
Approved Mainline Interim Tolls effective January 1, 2012

**System Average Unit Cost of Transportation**

| Line No | Particulars | Net Revenue Requirement ($000's) | Allocation Base | | Annual Unit Cost | | Daily Unit Cost | |
|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | | (d) | | (e) | |
| 1 | Fixed Energy | 76,148 | 3,938,676 | GJ | 19.3333983638 | $/GJ | 0.0529682147 | $/GJ |
| 2 | Transmission - Fixed | 1,169,509 | 4,862,440,154 | GJ-KM | 0.2405190214 | $/GJ-Km | 0.0006589562 | $/GJ-Km |
| 3 | Transmission - Variable | 48,954 | 1,053,676,682,785 | GJ-KM | - | $/GJ-Km | 0.0000464601 | $/GJ-Km |

**Storage Transportation Service**

| Line No | Particulars | Demand Toll ($/GJ/Month) | Commodity Toll ($/GJ) | Daily Equivalent ($/GJ) |
|---|---|---|---|---|
| | (a) | (b) | (c) | (d) |
| 4 | Centram MDA | 4.46187 | 0.00722 | 0.1539 |
| 5 | Union WDA | 31.41463 | 0.06896 | 1.1018 |
| 6 | Union NDA | 12.30579 | 0.02546 | 0.4300 |
| 7 | Union EDA | 8.00131 | 0.01505 | 0.2781 |
| 8 | KPUC EDA | 7.70246 | 0.01412 | 0.2674 |
| 9 | GMIT EDA | 14.16801 | 0.02929 | 0.4951 |
| 10 | Enbridge CDA | 1.69730 | 0.00024 | 0.0560 |
| 11 | Enbridge EDA | 4.84530 | 0.00757 | 0.1669 |
| 12 | Cornwall | 10.94987 | 0.02165 | 0.3816 |
| 13 | Philipsburg | 14.44301 | 0.02974 | 0.5046 |

**Firm Transportation - Short Notice**

| Line No | Particulars | Demand Toll ($/GJ/Month) | Commodity Toll ($/GJ) | Daily Equivalent *(1) ($/GJ) |
|---|---|---|---|---|
| | (a) | (b) | (c) | (d) |
| 14 | Kirkwall to Thorold - CDA | 3.87336 | 0.00487 | 0.1322 |
| 15 | Parkway to Goreway - CDA | 2.39507 | 0.00144 | 0.0802 |
| 16 | Parkway to Victoria Square #2 CDA | 3.17490 | 0.00326 | 0.1077 |
| 17 | Parkway to Schomberg #2 CDA | 3.12397 | 0.00314 | 0.1059 |

*(1) The Daily Equivalent Toll represents the minimum bid floor for ST-SN service.

**Delivery Pressure**

| Line No | Particulars | Demand Toll ($/GJ/Month) | Commodity Toll ($/GJ) | Daily Equivalent *(2) ($/GJ) |
|---|---|---|---|---|
| | (a) | (b) | (c) | (d) |
| 18 | Emerson - 1 (Viking) | 0.09571 | 0.00000 | 0.0032 |
| 19 | Emerson - 2 (Great Lakes) | 0.14114 | 0.00000 | 0.0046 |
| 20 | Dawn | 0.08038 | 0.00000 | 0.0026 |
| 21 | Niagara Falls | 0.59443 | 0.00000 | 0.0195 |
| 22 | Iroquois | 1.03785 | 0.00000 | 0.0341 |
| 23 | Chippawa | 1.03444 | 0.00000 | 0.0340 |
| 24 | East Hereford | 4.54054 | 0.03226 | 0.1815 |

*(2) The Demand Daily Equivalent Toll is only applicable to STS Injections, IT, Diversions and STFT.

**Union Dawn Receipt Point Surcharge**

| Line No | Particulars | Demand Toll ($/GJ/Month) | Commodity Toll ($/GJ) | Daily Equivalent ($/GJ) |
|---|---|---|---|---|
| | (a) | (b) | (c) | (d) |
| 25 | Union Dawn Receipt Point Surcharge | 0.09828 | 0.00000 | 0.0032 |

FT, STFT and Interruptible Transportation Tolls
Approved Mainline Interim Tolls effective January 1, 2012

| Line No. | Receipt Point | Delivery point | Demand Toll ($/GJ/MO) | Commodity Toll ($/GJ) | (FT, STFT Minimum Tolls)[ii] (100% LF FT Tolls) ($/GJ) | IT Bid Floor (110% FT Tolls) ($/GJ) |
|---|---|---|---|---|---|---|
| 1 | Union Parkway Belt | Centrat MDA | 40.47278 | 0.09008 | 1.4207 | 1.5628 |
| 2 | Union Parkway Belt | Union WDA | 31.16449 | 0.06841 | 1.0930 | 1.2023 |
| 3 | Union Parkway Belt | Nipigon WDA | 27.37231 | 0.05971 | 0.9596 | 1.0556 |
| 4 | Union Parkway Belt | Union NDA | 12.30620 | 0.02546 | 0.4301 | 0.4731 |
| 5 | Union Parkway Belt | Calstock NDA | 20.74300 | 0.04435 | 0.7264 | 0.7990 |
| 6 | Union Parkway Belt | Tunis NDA | 15.52374 | 0.03225 | 0.5427 | 0.5970 |
| 7 | Union Parkway Belt | GMIT NDA | 11.69247 | 0.02319 | 0.4076 | 0.4484 |
| 8 | Union Parkway Belt | Union SSMDA | 18.35505 | 0.03881 | 0.6423 | 0.7065 |
| 9 | Union Parkway Belt | Union NCDA | 5.29747 | 0.00861 | 0.1828 | 0.2011 |
| 10 | Union Parkway Belt | Union CDA | 2.07011 | 0.00053 | 0.0686 | 0.0755 |
| 11 | Union Parkway Belt | Enbridge CDA | 3.14523 | 0.00350 | 0.1069 | 0.1176 |
| 12 | Union Parkway Belt | Union EDA | 8.15784 | 0.01535 | 0.2836 | 0.3120 |
| 13 | Union Parkway Belt | Enbridge EDA | 10.97773 | 0.02175 | 0.3827 | 0.4210 |
| 14 | Union Parkway Belt | GMIT EDA | 14.26643 | 0.02945 | 0.4985 | 0.5484 |
| 15 | Union Parkway Belt | KPUC EDA | 7.70246 | 0.01412 | 0.2673 | 0.2940 |
| 16 | Union Parkway Belt | North Bay Junction | 8.81626 | 0.01670 | 0.3065 | 0.3372 |
| 17 | Union Parkway Belt | Enbridge SWDA | 6.15853 | 0.01054 | 0.2130 | 0.2343 |
| 18 | Union Parkway Belt | Union SWDA | 6.36578 | 0.01079 | 0.2201 | 0.2421 |
| 19 | Union Parkway Belt | Spruce | 40.47278 | 0.09008 | 1.4207 | 1.5628 |
| 20 | Union Parkway Belt | Emerson 1 | 38.02790 | 0.08441 | 1.3346 | 1.4681 |
| 21 | Union Parkway Belt | Emerson 2 | 38.02790 | 0.08441 | 1.3346 | 1.4681 |
| 22 | Union Parkway Belt | St. Clair | 6.63616 | 0.01165 | 0.2299 | 0.2529 |
| 23 | Union Parkway Belt | Dawn Export | 6.15853 | 0.01054 | 0.2130 | 0.2343 |
| 24 | Union Parkway Belt | Kirkwall | 2.37697 | 0.00178 | 0.0799 | 0.0879 |
| 25 | Union Parkway Belt | Niagara Falls | 4.27106 | 0.00617 | 0.1466 | 0.1613 |
| 26 | Union Parkway Belt | Chippawa | 4.31896 | 0.00628 | 0.1483 | 0.1631 |
| 27 | Union Parkway Belt | Iroquois | 10.16778 | 0.01983 | 0.3541 | 0.3895 |
| 28 | Union Parkway Belt | Cornwall | 11.01681 | 0.02180 | 0.3840 | 0.4224 |
| 29 | Union Parkway Belt | Napierville | 14.09626 | 0.02894 | 0.4923 | 0.5415 |
| 30 | Union Parkway Belt | Philipsburg | 14.44621 | 0.02975 | 0.5047 | 0.5552 |
| 31 | Union Parkway Belt | East Hereford | 18.15642 | 0.03835 | 0.6353 | 0.6988 |
| 32 | Union Parkway Belt | Welwyn | 46.28071 | 0.10354 | 1.6251 | 1.7876 |
| 33 | Union NCDA | Empress | 56.87397 | 0.12803 | 1.9978 | 2.1976 |
| 34 | Union NCDA | Transgas SSDA | 48.16057 | 0.10875 | 1.6922 | 1.8614 |
| 35 | Union NCDA | Centram SSDA | 44.61612 | 0.09962 | 1.5664 | 1.7230 |
| 36 | Union NCDA | Centram MDA | 39.26096 | 0.08782 | 1.3786 | 1.5165 |
| 37 | Union NCDA | Centrat MDA | 36.78642 | 0.08147 | 1.2909 | 1.4200 |
| 38 | Union NCDA | Union WDA | 27.47814 | 0.05979 | 0.9632 | 1.0595 |
| 39 | Union NCDA | Nipigon WDA | 23.68595 | 0.05110 | 0.8298 | 0.9128 |
| 40 | Union NCDA | Union NDA | 8.61984 | 0.01685 | 0.3003 | 0.3303 |
| 41 | Union NCDA | Calstock NDA | 17.05665 | 0.03574 | 0.5965 | 0.6562 |
| 42 | Union NCDA | Tunis NDA | 11.83738 | 0.02364 | 0.4128 | 0.4541 |
| 43 | Union NCDA | GMIT NDA | 8.00632 | 0.01458 | 0.2778 | 0.3056 |
| 44 | Union NCDA | Union SSMDA | 22.04140 | 0.04742 | 0.7720 | 0.8492 |
| 45 | Union NCDA | Union NCDA | 1.61112 | 0.00000 | 0.0530 | 0.0583 |
| 46 | Union NCDA | Union CDA | 5.75646 | 0.00915 | 0.1985 | 0.2184 |
| 47 | Union NCDA | Enbridge CDA | 5.20928 | 0.00836 | 0.1797 | 0.1977 |
| 48 | Union NCDA | Union EDA | 9.89018 | 0.01945 | 0.3447 | 0.3792 |
| 49 | Union NCDA | Enbridge EDA | 11.86043 | 0.02382 | 0.4137 | 0.4551 |
| 50 | Union NCDA | GMIT EDA | 15.84503 | 0.03319 | 0.5541 | 0.6095 |
| 51 | Union NCDA | KPUC EDA | 9.52199 | 0.01840 | 0.3315 | 0.3647 |
| 52 | Union NCDA | North Bay Junction | 5.12991 | 0.00809 | 0.1768 | 0.1945 |
| 53 | Union NCDA | Enbridge SWDA | 9.84488 | 0.01915 | 0.3429 | 0.3772 |
| 54 | Union NCDA | Union SWDA | 10.05213 | 0.01940 | 0.3499 | 0.3849 |
| 55 | Union NCDA | Spruce | 36.78642 | 0.08147 | 1.2909 | 1.4200 |
| 56 | Union NCDA | Emerson 1 | 39.62795 | 0.08806 | 1.3909 | 1.5300 |
| 57 | Union NCDA | Emerson 2 | 39.62795 | 0.08806 | 1.3909 | 1.5300 |
| 58 | Union NCDA | St. Clair | 10.32252 | 0.02026 | 0.3597 | 0.3957 |
| 59 | Union NCDA | Dawn Export | 9.84488 | 0.01915 | 0.3429 | 0.3772 |
| 60 | Union NCDA | Kirkwall | 6.06332 | 0.01039 | 0.2097 | 0.2307 |
| 61 | Union NCDA | Niagara Falls | 7.95741 | 0.01478 | 0.2764 | 0.3040 |
| 62 | Union NCDA | Chippawa | 8.00531 | 0.01489 | 0.2781 | 0.3059 |
| 63 | Union NCDA | Iroquois | 11.79008 | 0.02368 | 0.4113 | 0.4524 |
| 64 | Union NCDA | Cornwall | 12.59522 | 0.02554 | 0.4396 | 0.4836 |
| 65 | Union NCDA | Napierville | 15.67466 | 0.03268 | 0.5480 | 0.6028 |
| 66 | Union NCDA | Philipsburg | 16.02462 | 0.03349 | 0.5603 | 0.6163 |
| 67 | Union NCDA | East Hereford | 19.73483 | 0.04209 | 0.6909 | 0.7600 |
| 68 | Union NCDA | Welwyn | 44.61612 | 0.09962 | 1.5664 | 1.7230 |
| 69 | Union SSMDA | Empress | 45.07892 | 0.10076 | 1.5828 | 1.7411 |
| 70 | Union SSMDA | Transgas SSDA | 36.36551 | 0.08147 | 1.2771 | 1.4048 |
| 71 | Union SSMDA | Centram SSDA | 32.82107 | 0.07234 | 1.1513 | 1.2664 |
| 72 | Union SSMDA | Centram MDA | 27.43845 | 0.06048 | 0.9626 | 1.0589 |
| 73 | Union SSMDA | Centrat MDA | 27.41259 | 0.05981 | 0.9610 | 1.0571 |
| 74 | Union SSMDA | Union WDA | 37.50337 | 0.08335 | 1.3164 | 1.4480 |
| 75 | Union SSMDA | Nipigon WDA | 40.51306 | 0.09017 | 1.4221 | 1.5643 |
| 76 | Union SSMDA | Union NDA | 29.05013 | 0.06427 | 1.0194 | 1.1213 |
| 77 | Union SSMDA | Calstock NDA | 37.48693 | 0.08316 | 1.3156 | 1.4472 |
| 78 | Union SSMDA | Tunis NDA | 32.26767 | 0.07106 | 1.1320 | 1.2452 |

# Daily currency converter

Convert to and from Canadian dollars, using the latest noon rates.

## Currency Converter

**Amount:** 1.00 cash rate:

**From:** Canadian Dollar

**To:** U.S. dollar

Convert

**Answer:** 0.99

**Exchange Rate:** 0.9940

**Summary:** On July 27, 2012, 1.00 Canadian Dollar(s) = 0.99 U.S. dollar(s), at an exchange rate of 0.9940 (using nominal rate).

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**ENERGY NORTH NATURAL GAS, INC.**

**Peak 2012 - 2013 Winter Cost of Gas Filing**
**Supply and Commodity Costs, Volumes and Rates**

| For Month of: | Reference | Nov-12 | Dec-12 | Jan-13 | Feb-13 | Mar-13 | Apr-13 | Peak Nov- Apr |
|---|---|---|---|---|---|---|---|---|
| (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) |
| **Supply and Commodity Costs** | | | | | | | | |
| **Pipeline Gas:** | | | | | | | | |
| Dawn Supply | ln 63 * ln 102 | | | | | | | |
| Niagara Supply | ln 64 * ln 107 | | | | | | | |
| TGP Supply (Direct) | ln 65 * ln 123 | | | | | | | |
| Dracut Supply 1 - Baseload | ln 66 * ln 112 | | | | | | | |
| Dracut Supply 2 - Swing | ln 67 * ln 117 | | | | | | | |
| City Gate Delivered Supply | ln 68 * ln 129 | | | | | | | |
| LNG Truck | ln 69 * ln 131 | | | | | | | |
| Propane Truck | ln 70 * ln 133 | | | | | | | |
| PNGTS | ln 71 * ln 138 | | | | | | | |
| Granite Ridge | ln 72 * ln 143 | | | | | | | |
| Subtotal Pipeline Gas Costs | | $ 3,596,339 | $ 4,307,613 | $ 6,064,958 | $ 5,085,096 | $ 3,830,237 | $ 3,683,307 | $ 26,567,550 |
| **Volumetric Transportation Costs** | | | | | | | | |
| Dawn Supply | ln 63 * ln 176 | | | | | | | |
| Niagara Supply | ln 64 * ln 187 | | | | | | | |
| TGP Supply (Direct) | ln 65 * ln 214 | | | | | | | |
| Dracut Supply 1 - Baseload | ln 66 * ln 235 | | | | | | | |
| Dracut Supply 2 - Swing | ln 67 * ln 235 | | | | | | | |
| City Gate Delivered Supply | ln 68 * ln 235 | | | | | | | |
| TGP Storage - Withdrawals | ln 77 * ln 165 | | | | | | | |
| **Total Volumetric Transportation Costs** | | $ 271,717 | $ 334,812 | $ 364,836 | $ 325,657 | $ 314,632 | $ 255,390 | $ 1,867,044 |
| **Less - Gas Refill:** | | | | | | | | |
| LNG Truck | ln 86 * ln 150 | | | | | | | |
| Propane | ln 87 * ln 151 | | | | | | | |
| TGP Storage Refill | ln 88 * ln 121 | | | | | | | |
| Storage Refill (Trans.) | ln 88 * ln 214 | | | | | | | |
| Subtotal Refills | | $ (655,834) | $ (7,528) | $ (238,320) | $ - | $ (15,610) | $ (886,634) | $ (1,803,927) |
| **Total Supply & Pipeline Commodity Costs** | ln 23 + ln 34 + ln 42 | $ 3,212,222 | $ 4,634,896 | $ 6,191,474 | $ 5,410,754 | $ 4,129,258 | $ 3,052,063 | $ 26,630,667 |
| **Storage Gas:** | | | | | | | | |
| TGP Storage - Withdrawals | ln 77 * ln 157 | $ 543,878 | $ 2,138,887 | $ 2,575,290 | $ 2,209,739 | $ 1,631,633 | $ 22,276 | $ 9,121,704 |
| **Produced Gas:** | | | | | | | | |
| LNG Vapor | ln 80 * ln 145 | | | | | | | |
| Propane | ln 81 * ln 147 | | | | | | | |
| **Total Produced Gas** | ln 50 + ln 51 | $ 8,385 | $ 8,483 | $ 251,683 | $ 7,362 | $ 7,862 | $ 7,591 | $ 291,366 |
| **Total Commodity Gas & Trans. Costs** | ln 44 + ln 47 + ln 53 | $ 3,764,485 | $ 6,782,267 | $ 9,018,447 | $ 7,627,855 | $ 5,768,753 | $ 3,081,930 | $ 36,043,738 |
| | | | | | | | | $ 79,988,370 |

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**ENERGY NORTH NATURAL GAS, INC.** **REDACTED**

**Peak 2012 - 2013 Winter Cost of Gas Filing**
**Supply and Commodity Costs, Volumes and Rates**

| For Month of: | Reference | Nov-12 | Dec-12 | Jan-13 | Feb-13 | Mar-13 | Apr-13 | Peak Nov- Apr |
|---|---|---|---|---|---|---|---|---|
| (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) |
| **Volumes (Therms)** | | | | | | | | |
| **Pipeline Gas:** | See Schedule 11A | | | | | | | |
| Dawn Supply | | 924,000 | 926,310 | 954,800 | 862,400 | 954,800 | 820,050 | 5,442,360 |
| Niagara Supply | | 721,490 | 745,360 | 745,360 | 672,980 | 745,360 | 721,490 | 4,352,040 |
| TGP Supply (Direct) | | 5,292,980 | 5,155,150 | 5,155,150 | 4,656,190 | 5,155,150 | 5,272,190 | 30,686,810 |
| Dracut Supply 1 - Baseload | | - | 2,380,840 | 2,380,840 | 2,150,610 | - | - | 6,912,290 |
| Dracut Supply 2 - Swing | | 3,531,220 | 957,880 | 1,983,520 | 2,142,140 | 3,002,230 | 3,362,590 | 14,979,580 |
| City Gate Delivered Supply | | - | - | - | - | - | - | - |
| LNG Truck | | 21,560 | 22,330 | 680,680 | - | 44,660 | - | 769,230 |
| Propane Truck | | - | - | - | - | - | - | - |
| PNGTS | | 58,520 | 76,230 | 83,160 | 71,610 | 66,990 | 46,970 | 403,480 |
| Granite Ridge | | - | - | - | - | - | - | - |
| Subtotal Pipeline Volumes | | 10,549,770 | 10,264,100 | 11,983,510 | 10,555,930 | 9,969,190 | 10,223,290 | 63,545,790 |
| **Storage Gas:** | | | | | | | | |
| TGP Storage | | 1,223,530 | 4,811,730 | 5,793,480 | 4,971,120 | 3,670,590 | 52,360 | 20,522,810 |
| **Produced Gas:** | | | | | | | | |
| LNG Vapor | | 21,560 | 22,330 | 710,710 | 20,790 | 22,330 | 21,560 | 819,280 |
| Propane | | - | - | - | - | - | - | - |
| Subtotal Produced Gas | | 21,560 | 22,330 | 710,710 | 20,790 | 22,330 | 21,560 | 819,280 |
| **Less - Gas Refill:** | | | | | | | | |
| LNG Truck | | (21,560) | (22,330) | (680,680) | - | (44,660) | - | (769,230) |
| Propane | | - | - | - | - | - | - | - |
| TGP Storage Refill | | (1,851,080) | - | - | - | - | (2,279,200) | (4,130,280) |
| Subtotal Refills | | (1,872,640) | (22,330) | (680,680) | - | (44,660) | (2,279,200) | (4,899,510) |
| **Total Sendout Volumes** | | 9,922,220 | 15,075,830 | 17,807,020 | 15,547,840 | 13,617,450 | 8,018,010 | 79,988,370 |

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**ENERGY NORTH NATURAL GAS, INC.**

**Peak 2012 - 2013 Winter Cost of Gas Filing**
**Supply and Commodity Costs, Volumes and Rates**

| For Month of: | Reference | Nov-12 | Dec-12 | Jan-13 | Feb-13 | Mar-13 | Apr-13 | Peak Nov- Apr |
|---|---|---|---|---|---|---|---|---|
| (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) |
| **Gas Costs and Volumetric Transportation Rates** | | | | | | | | |
| **Pipeline Gas:** | | | | | | | | |
| **Dawn Supply** | | | | | | | | Average Rate |
| NYMEX Price | Sch 7, ln 10/10 | [redacted] | | | | | | |
| Basis Differential | | | | | | | | |
| **Net Commodity Costs** | | | | | | | | |
| **Niagara Supply** | | | | | | | | |
| NYMEX Price | Sch 7, ln 10/10 | [redacted] | | | | | | |
| Basis Differential | | | | | | | | |
| **Net Commodity Costs** | | | | | | | | |
| **Dracut Supply 1 - Baseload** | | | | | | | | |
| Commodity Costs - NYMEX Price | Sch 7, ln 10 / 10 | [redacted] | | | | | | |
| Basis Differential | | | | | | | | |
| **Net Commodity Costs** | | | | | | | | |
| **Dracut Supply 2 - Swing** | | | | | | | | |
| Commodity Costs - NYMEX Price | Sch 7, ln 10 / 10 | [redacted] | | | | | | |
| Basis Differential | | | | | | | | |
| **Net Commodity Costs** | | | | | | | | |
| **TGP Supply (Direct)** | | | | | | | | |
| NYMEX Price | Sch 7, ln 10/10 | [redacted] | | | | | | |
| Basis Differential | | | | | | | | |
| **Net Commodity Costs** | | | | | | | | |
| **City Gate Delivered Supply** | | | | | | | | |
| NYMEX Price | Sch 7, ln 10/10 | [redacted] | | | | | | |
| Basis Differential | | | | | | | | |
| **Net Commodity Costs** | | | | | | | | |
| **LNG Truck** | Sch 7, ln 10/10 | **$0.3106** | **$0.3371** | **$0.3501** | **$0.3515** | **$0.3495** | **$0.3475** | **$0.3411** |
| **Propane Truck** | NYMEX - Propane | **$0.0000** | **$0.0000** | **$0.0000** | **$0.0000** | **$0.0000** | **$0.0000** | **$0.0000** |
| **PNGTS** | | | | | | | | |
| NYMEX Price | Sch 7, ln 10/10 | [redacted] | | | | | | |
| Additional Cost | | | | | | | | |
| **Net Commodity Cost** | | | | | | | | |
| **Granite Ridge** | | | | | | | | |
| NYMEX Price | Sch 7, ln 10/10 | [redacted] | | | | | | |
| Additional Cost | | | | | | | | |
| **Net Commodity Cost** | | | | | | | | |
| **LNG Vapor (Storage)** | Sch 16, ln 95 /10 | **$0.3889** | **$0.3799** | **$0.3541** | **$0.3541** | **$0.3521** | **$0.3521** | **$0.3635** |
| **Propane** | Sch 16, ln 66 /10 | **$1.4833** | **$1.4833** | **$1.4833** | **$1.4833** | **$1.4833** | **$1.4833** | **$1.4833** |
| **Storage Refill:** | | | | | | | | |
| **LNG Truck** | ln 131 | **$0.3106** | **$0.3371** | **$0.3501** | **$0.3515** | **$0.3495** | **$0.3475** | **$0.3635** |
| **Propane** | ln 133 | **$0.0000** | **$0.0000** | **$0.0000** | **$0.0000** | **$0.0000** | **$0.0000** | **$1.4833** |

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**ENERGY NORTH NATURAL GAS, INC.**

**Peak 2012 - 2013 Winter Cost of Gas Filing**
**Supply and Commodity Costs, Volumes and Rates**

| For Month of: (a) | Reference (b) | Nov-12 (c) | Dec-12 (d) | Jan-13 (e) | Feb-13 (f) | Mar-13 (g) | Apr-13 (h) | Peak Nov- Apr (i) |
|---|---|---|---|---|---|---|---|---|
| | | | | | | | | **REDACTED** |
| **Per Unit Volumetric Transportation Rates** | | | | | | | | |
| **Dawn Supply Volumetric Transportation Charge** | | | | | | | | |
| **Commodity Costs** | ln 102 | **$0.3496** | **$0.3741** | **$0.3781** | **$0.3795** | **$0.3775** | **$0.3685** | **$0.3712** |
| TransCanada - Commodity Rate/GJ | Union Parkway to Iroquois | $0.00198 | $0.00198 | $0.00198 | $0.00198 | $0.00198 | $0.00198 | $0.00198 |
| Conversion Rate GL to MMBTU | | 1.0551 | 1.0551 | 1.0551 | 1.0551 | 1.0551 | 1.0551 | 1.0551 |
| Conversion Rate to US$ | 07/27/2012 | 0.9940 | 0.9940 | 0.9940 | 0.9940 | 0.9940 | 0.9940 | 0.9940 |
| Commodity Rate/US$ | ln 160 x ln 161 x ln 162 | $0.00208 | $0.00208 | $0.00208 | $0.00208 | $0.00208 | $0.00208 | $0.00208 |
| TransCanada Fuel % | Union Parkway to Iroquois | 1.20% | 1.09% | 1.36% | 1.30% | 1.00% | 0.88% | 1.14% |
| TransCanada Fuel * Percentage | ln 158 x ln 164 | $0.00419 | $0.00408 | $0.00514 | $0.00493 | $0.00378 | $0.00324 | $0.00423 |
| Subtotal TransCanada | | **$0.00627** | **$0.00616** | **$0.00722** | **$0.00701** | **$0.00586** | **$0.00532** | **$0.00631** |
| IGTS - Z1 RTS Commodity | First Revised Sheet No. 4 | $0.00030 | $0.00030 | $0.00030 | $0.00030 | $0.00030 | $0.00030 | $0.00030 |
| IGTS - Z1 RTS ACA Rate Commodity | Third Revised Sheet 4A | $0.00018 | $0.00018 | $0.00018 | $0.00018 | $0.00018 | $0.00018 | $0.00018 |
| IGTS - Z1 RTS Deferred Asset Surcharge | Third Revised Sheet 4A | $0.00000 | $0.00000 | $0.00000 | $0.00000 | $0.00000 | $0.00000 | $0.00000 |
| Subtotal IGTS - Trans Charge - Z1 RTS Commodity | | **$0.00048** | **$0.00048** | **$0.00048** | **$0.00048** | **$0.00048** | **$0.00048** | **$0.00048** |
| TGP NET-NE - Comm. Segments 3 & 4 | Seventh Rev Sheet No.15 | $0.00018 | $0.00018 | $0.00018 | $0.00018 | $0.00018 | $0.00018 | $0.00018 |
| IGTS -Fuel Use Factor - Percentage | Third Revised Sheet 4A | 1.00% | 1.00% | 1.00% | 1.00% | 1.00% | 1.00% | 1.00% |
| IGTS -Fuel Use Factor - Fuel * Percentage | ln 158 x ln 172 | **$0.00350** | **$0.00374** | **$0.00378** | **$0.00380** | **$0.00378** | **$0.00369** | **$0.00371** |
| TGP NET-284 - Fuel Charge % Z 4-6 | Sixth Rev Sheet No. 32 | 0.91% | 0.91% | 0.91% | 0.91% | 0.91% | 0.91% | 0.91% |
| TGP NET-284 -Fuel Use Factor - Fuel * % | ln 158 x ln 174 | **$0.00318** | **$0.00340** | **$0.00344** | **$0.00345** | **$0.00344** | **$0.00335** | **$0.00338** |
| **Total Volumetric Transportation Charge - Dawn Supply** | | **$0.01361** | **$0.01396** | **$0.01510** | **$0.01492** | **$0.01373** | **$0.01302** | **$0.01406** |
| **Niagara Supply Volumetric Transportation Charge** | | | | | | | | |
| **Commodity Costs** | Ln 107 | [redacted] | | | | | | |
| TGP FTA - FTA Z 5-6 Comm. Rate | Seventh Rev Sheet No.15 | | | | | | | |
| TGP FTA - FTA Z 5-6 - ACA Rate | Seventh Rev Sheet No.15 | | | | | | | |
| Subtotal TGP FTA - FTA Z 5-6 Commodity Rate | | | | | | | | |
| TGP FTA Fuel Charge % Z 5-6 | Sixth Rev Sheet No. 32 | | | | | | | |
| TGP FTA Fuel * Percentage | ln 180 x ln 185 | | | | | | | |
| **Total Volumetric Transportation Rate - Niagra Supply** | | | | | | | | |

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**ENERGY NORTH NATURAL GAS, INC.**

**Peak 2012 - 2013 Winter Cost of Gas Filing**
**Supply and Commodity Costs, Volumes and Rates**

| For Month of: | Reference | Nov-12 | Dec-12 | Jan-13 | Feb-13 | Mar-13 | Apr-13 | Peak Nov- Apr |
|---|---|---|---|---|---|---|---|---|
| (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) |
| **TGP Direct Volumetric Transportation Charge** | | | | | | | | Average Rate |
| **Commodity Costs** | Ln 121 | [redacted] | | | | | | |
| TGP - Max Comm. Base Rate - Z 0-6 | Seventh Rev Sheet No.15 | $0.03124 | $0.03124 | $0.03124 | $0.03124 | $0.03124 | $0.03124 | $0.03124 |
| TGP - Max Commodity ACA Rate - Z 0-6 | Seventh Rev Sheet No.15 | $0.00018 | $0.00018 | $0.00018 | $0.00018 | $0.00018 | $0.00018 | $0.00018 |
| Subtotal TGP - Max Comm. Rate Z 0-6 | | $0.03142 | $0.03142 | $0.03142 | $0.03142 | $0.03142 | $0.03142 | $0.03142 |
| Prorated Percentage | | 32.60% | 32.60% | 32.60% | 32.60% | 32.60% | 32.60% | 32.60% |
| Prorated TGP - Max Commodity Rate - Z 0-6 | | **$0.01024** | **$0.01024** | **$0.01024** | **$0.01024** | **$0.01024** | **$0.01024** | **$0.01024** |
| TGP - Max Comm. Base Rate - Z 1-6 | Seventh Rev Sheet No.15 | $0.02723 | $0.02723 | $0.02723 | $0.02723 | $0.02723 | $0.02723 | $0.02723 |
| TGP - Max Commodity ACA Rate - Z 1-6 | Seventh Rev Sheet No.15 | $0.00018 | $0.00018 | $0.00018 | $0.00018 | $0.00018 | $0.00018 | $0.00018 |
| Subtotal TGP - Max Commodity Rate - Z 1-6 | | $0.02741 | $0.02741 | $0.02741 | $0.02741 | $0.02741 | $0.02741 | $0.02741 |
| Prorated Percentage | | 67.40% | 67.40% | 67.40% | 67.40% | 67.40% | 67.40% | 67.40% |
| Prorated TGP - Trans Charge - Max Commodity Rate - Z 1-6 | | **$0.01847** | **$0.01847** | **$0.01847** | **$0.01847** | **$0.01847** | **$0.01847** | **$0.01847** |
| TGP - Fuel Charge % - Z 0 -6 | Sixth Rev Sheet No. 32 | 4.00% | 4.00% | 4.00% | 4.00% | 4.00% | 4.00% | 4.00% |
| Prorated Percentage | | 32.6% | 32.6% | 32.6% | 32.6% | 32.6% | 32.6% | 32.6% |
| Prorated TGP Fuel Charge % - Z 0-6 | | 1.30% | 1.30% | 1.30% | 1.30% | 1.30% | 1.30% | 1.30% |
| TGP - Fuel Charge % - Z 1 -6 | Sixth Rev Sheet No. 32 | 3.51% | 3.51% | 3.51% | 3.51% | 3.51% | 3.51% | 3.51% |
| Prorated Percentage | | 67.40% | 67.40% | 67.40% | 67.40% | 67.40% | 67.40% | 67.40% |
| Prorated TGP Fuel Charge - Fuel Charge % - Z 1-6 | | 2.37% | 2.37% | 2.37% | 2.37% | 2.37% | 2.37% | 2.37% |
| TGP - Fuel Charge % - Z 0-6 | ln 194 x ln 208 | **$0.00405** | **$0.00440** | **$0.00457** | **$0.00458** | **$0.00456** | **$0.00453** | **$0.00445** |
| TGP - Fuel Charge % - Z 1-6 | ln 194 x ln 211 | **$0.00735** | **$0.00798** | **$0.00828** | **$0.00832** | **$0.00827** | **$0.00822** | **$0.00807** |
| **Total Volumetric Transportation Rate - TGP (Direct)** | | **$0.04011** | **$0.04109** | **$0.04157** | **$0.04162** | **$0.04154** | **$0.04147** | **$0.04123** |
| **TGP (Zone 6 Purchase) Volumetric Transportation Charge** | | | | | | | | |
| **Commodity Costs** | Ln 121 | [redacted] | | | | | | |
| TGP - Max Comm. Base Rate - Z 6-6 | Seventh Rev Sheet No.15 | $0.00334 | $0.00334 | $0.00334 | $0.00334 | $0.00334 | $0.00334 | $0.00334 |
| TGP - Max Commodity ACA Rate - Z 6-6 | Seventh Rev Sheet No.15 | $0.00018 | $0.00018 | $0.00018 | $0.00018 | $0.00018 | $0.00018 | $0.00018 |
| Subtotal TGP - Max Commodity Rate - Z 6-6 | | **$0.00352** | **$0.00352** | **$0.00352** | **$0.00352** | **$0.00352** | **$0.00352** | **$0.00352** |
| TGP - Fuel Charge % - Z 6-6 | Sixth Rev Sheet No. 32 | 0.38% | 0.38% | 0.38% | 0.38% | 0.38% | 0.38% | 0.38% |
| TGP - Fuel Charge | ln 217 x ln 222 | **$0.00118** | **$0.00128** | **$0.00133** | **$0.00134** | **$0.00133** | **$0.00132** | **$0.00130** |
| **Total Vol. Trans. Rate - TGP (Zone 6)** | | **$0.00470** | **$0.00480** | **$0.00485** | **$0.00486** | **$0.00485** | **$0.00484** | **$0.00482** |
| **TGP Dracut** | | | | | | | | |
| **Commodity Costs - NYMEX Price** | Ln 112 | [redacted] | | | | | | |
| TGP - Trans Charge - Comm. - Z 6-6 | Seventh Rev Sheet No.15 | | | | | | | |
| TGP - Trans Charge - ACA Rate - Z6-6 | Seventh Rev Sheet No.15 | | | | | | | |
| Subtotal TGP - Trans Charge - Max Commodity Rate - Z 6-6 | | | | | | | | |
| TGP - Fuel Charge % - Z 6-6 | Sixth Rev Sheet No. 32 | | | | | | | |
| TGP - Fuel Charge | ln 228 x ln 233 | | | | | | | |
| **Total Volumetric Transportation Rate - TGP Dracut** | | | | | | | | |

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| | RATES (All in $ Per Dth) | | | | | | |
|---|---|---|---|---|---|---|---|
| | | Non-Settlement Recourse & Eastchester | Settlement Recourse Rates — Applicable to Non-Eastchester/Non-Contesting Shippers 2/ | | | | |
| | Minimum | Initial Rates 3/ | Effective 1/1/2003 | Effective 7/1/2004 | Effective 1/1/2005 | Effective 1/1/2006 | Effective 1/1/2007 |
| RTS DEMAND: | | | | | | | |
| Zone 1 | $0.0000 | $7.5637 | $7.5637 | $6.9586 | $6.8514 | $6.7788 | $6.5971 |
| Zone 2 | $0.0000 | $6.4976 | $6.4976 | $5.9778 | $5.8857 | $5.8233 | $5.6673 |
| Inter-Zone | $0.0000 | $12.7150 | $12.7150 | $11.6978 | $11.5177 | $11.3956 | $11.0902 |
| Zone 1 (MFV) 1/ | $0.0000 | $5.3607 | $5.3607 | $4.9318 | $4.8559 | $4.8044 | $4.6757 |
| RTS COMMODITY: | | | | | | | |
| Zone 1 | $0.0030 | $0.0030 | $0.0030 | $0.0030 | $0.0030 | $0.0030 | $0.0030 |
| Zone 2 | $0.0024 | $0.0024 | $0.0024 | $0.0024 | $0.0024 | $0.0024 | $0.0024 |
| Inter-Zone | $0.0054 | $0.0054 | $0.0054 | $0.0054 | $0.0054 | $0.0054 | $0.0054 |
| Zone 1 (MFV) 1/ | $0.0300 | $0.1506 | $0.1506 | $0.1386 | $0.1364 | $0.1350 | $0.1314 |
| ITS COMMODITY: | | | | | | | |
| Zone 1 | $0.0030 | $0.2517 | $0.2517 | $0.2318 | $0.2283 | $0.2259 | $0.2199 |
| Zone 2 | $0.0024 | $0.2160 | $0.2160 | $0.1989 | $0.1959 | $0.1938 | $0.1887 |
| Inter-Zone | $0.0054 | $0.4234 | $0.4234 | $0.3900 | $0.3840 | $0.3800 | $0.3700 |
| Zone 1 (MFV) 1/ | $0.0300 | $0.3268 | $0.3268 | $0.3007 | $0.2960 | $0.2929 | $0.2850 |
| MAXIMUM VOLUMETRIC CAPACITY RELEASE RATE 4/: | | | | | | | |
| Zone 1 | $0.0000 | $0.2487 | $0.2487 | $0.2288 | $0.2253 | $0.2229 | $0.2169 |
| Zone 2 | $0.0000 | $0.2136 | $0.2136 | $0.1965 | $0.1935 | $0.1915 | $0.1863 |
| Inter-Zone | $0.0000 | $0.4180 | $0.4180 | $0.3846 | $0.3787 | $0.3746 | $0.3646 |
| Zone 1 (MFV) 1/ | $0.0000 | $0.1762 | $0.1762 | $0.1621 | $0.1596 | $0.1580 | $0.1537 |

**SEE SHEET NO. 4A FOR ADJUSTMENTS TO RATES WHICH MAY BE APPLICABLE

(Footnotes continued on Sheet 4.01)

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1/ As authorized pursuant to order of the Federal Energy Regulatory Commission, Docket Nos. RS92-17-003, et al., dated June 18, 1993 (63 FERC para. 61,285).

2/ Settlement Recourse Rates were established in Iroquois' Settlement dated August 29, 2003, which was approved by Commission order issued Oct. 24, 2003, in Docket No. RP03-589-000. That Settlement also established a moratorium on changes to the Settlement Rates until January 1, 2008, defines the Non-Eastchester/Non-Contesting parties to which it applies, and provides that Iroquois' TCRA will be terminated on July 1, 2004.

3/ See Sections 1.2 and 4.3 of the Settlement referenced in footnote 2. As directed by the Commission's January 30, 2004 Order in Docket No. RP04-136, the Eastchester Initial Rates apply for service to Eastchester Shippers prior to the July 1, 2004 effective date of the rates set forth on Sheet No. 4C.

4/ No rate cap shall apply to any capacity releases with terms of less than or equal to one year pursuant to FERC Order Nos. 712 et al.

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To the extent applicable, the following adjustments apply:

ACA ADJUSTMENT:

| | |
|---|---|
| Commodity | 0.0018 |

MEASUREMENT VARIANCE/FUEL USE FACTOR:

| | |
|---|---|
| Minimum | 0.00% |
| Maximum (Non-Eastchester Shipper) | 1.00% |
| Maximum (Eastchester Shipper) | 4.50% |
| Maximum (Brookfield Shipper) | 1.20% |

RATES PER DEKATHERM

COMMODITY RATES
RATE SCHEDULE FOR FT-A

Base Commodity Rates

| RECEIPT ZONE | DELIVERY ZONE 0 | L | 1 | 2 | 3 | 4 | 5 | 6 |
|---|---|---|---|---|---|---|---|---|
| 0 | $0.0032 | | $0.0115 | $0.0177 | $0.0219 | $0.2751 | $0.2625 | $0.3124 |
| L | | $0.0012 | | | | | | |
| 1 | $0.0042 | | $0.0081 | $0.0147 | $0.0179 | $0.2339 | $0.2385 | $0.2723 |
| 2 | $0.0167 | | $0.0087 | $0.0012 | $0.0028 | $0.0757 | $0.1214 | $0.1345 |
| 3 | $0.0207 | | $0.0169 | $0.0026 | $0.0002 | $0.1012 | $0.1400 | $0.1528 |
| 4 | $0.0250 | | $0.0205 | $0.0087 | $0.0105 | $0.0468 | $0.0662 | $0.1073 |
| 5 | $0.0284 | | $0.0256 | $0.0100 | $0.0118 | $0.0659 | $0.0653 | $0.0811 |
| 6 | $0.0346 | | $0.0300 | $0.0143 | $0.0163 | $0.1014 | $0.0549 | $0.0334 |

Minimum
Commodity Rates 1/, 2/

| RECEIPT ZONE | DELIVERY ZONE 0 | L | 1 | 2 | 3 | 4 | 5 | 6 |
|---|---|---|---|---|---|---|---|---|
| 0 | $0.0050 | | $0.0133 | $0.0195 | $0.0237 | $0.0268 | $0.0302 | $0.0364 |
| L | | $0.0030 | | | | | | |
| 1 | $0.0060 | | $0.0099 | $0.0165 | $0.0197 | $0.0228 | $0.0274 | $0.0318 |
| 2 | $0.0185 | | $0.0105 | $0.0030 | $0.0046 | $0.0074 | $0.0118 | $0.0161 |
| 3 | $0.0225 | | $0.0187 | $0.0044 | $0.0020 | $0.0099 | $0.0136 | $0.0181 |
| 4 | $0.0268 | | $0.0223 | $0.0105 | $0.0123 | $0.0046 | $0.0064 | $0.0110 |
| 5 | $0.0302 | | $0.0274 | $0.0118 | $0.0136 | $0.0064 | $0.0064 | $0.0084 |
| 6 | $0.0364 | | $0.0318 | $0.0161 | $0.0181 | $0.0104 | $0.0059 | $0.0038 |

Maximum
Commodity Rates 1/, 2/, 3/

| RECEIPT ZONE | DELIVERY ZONE 0 | L | 1 | 2 | 3 | 4 | 5 | 6 |
|---|---|---|---|---|---|---|---|---|
| 0 | $0.0050 | | $0.0133 | $0.0195 | $0.0237 | $0.2769 | $0.2643 | $0.3142 |
| L | | $0.0030 | | | | | | |
| 1 | $0.0060 | | $0.0099 | $0.0165 | $0.0197 | $0.2357 | $0.2403 | $0.2741 |
| 2 | $0.0185 | | $0.0105 | $0.0030 | $0.0046 | $0.0775 | $0.1232 | $0.1363 |
| 3 | $0.0225 | | $0.0187 | $0.0044 | $0.0020 | $0.1030 | $0.1418 | $0.1546 |
| 4 | $0.0268 | | $0.0223 | $0.0105 | $0.0123 | $0.0486 | $0.0680 | $0.1091 |
| 5 | $0.0302 | | $0.0274 | $0.0118 | $0.0136 | $0.0677 | $0.0671 | $0.0829 |
| 6 | $0.0364 | | $0.0318 | $0.0161 | $0.0181 | $0.1032 | $0.0567 | $0.0352 |

Notes:

1/ Includes a per Dth charge for (ACA) Annual Charge Adjustment of $0.0018
2/ The applicable F&LR's and EPCR's, determined pursuant to Article XXXVII of the General Terms and Conditions, are listed on Sheet No. 32. For service that is rendered entirely by displacement and for gas scheduled and allocated for receipt at the Dracut, Massachusetts receipt point, Shipper shall render only the quantity of gas associated with Losses of 0.21%.
3/ Includes a per Dth charge for the PS/GHG Surcharge Adjustment per Article XXXVIII of the General Terms and Conditions of $0.0000.

RATE SCHEDULE NET 284 1/, 2/

Notes:

1/ The rates for service under Rate Schedule NET-284 shall be equal to the applicable rates for service under Rate Schedule FT-A in the Summary of Rates and Charges on Sheet Nos. 14 – 17.

2/ The applicable F&LR's and EPCR's, determined pursuant to Article XXXVII of the General Terms and Conditions, are listed on Sheet No. 32. For service rendered entirely by displacement and for gas scheduled and allocated for receipt at the Dracut, Massachusetts receipt point, Shipper shall render only the quantity of gas associated with Losses of 0.21%.

FUEL AND EPCR

F&LR 1/, 2/, 3/, 4/

| RECEIPT ZONE | DELIVERY ZONE 0 | L | 1 | 2 | 3 | 4 | 5 | 6 |
|---|---|---|---|---|---|---|---|---|
| 0 | 0.56% | | 1.46% | 2.11% | 2.55% | 3.02% | 3.39% | 4.00% |
| L | | 0.35% | | | | | | |
| 1 | 0.67% | | 1.10% | 1.80% | 2.13% | 2.58% | 3.09% | 3.51% |
| 2 | 2.15% | | 1.16% | 0.34% | 0.52% | 0.86% | 1.36% | 1.77% |
| 3 | 2.61% | | 2.17% | 0.52% | 0.24% | 1.14% | 1.57% | 2.03% |
| 4 | 3.10% | | 2.41% | 1.15% | 1.35% | 0.53% | 0.75% | 1.20% |
| 5 | 3.50% | | 3.09% | 1.37% | 1.58% | 0.75% | 0.74% | 0.91% |
| 6 | 4.15% | | 3.51% | 1.79% | 2.03% | 1.13% | 0.62% | 0.38% |

EPCR 3/, 4/

| RECEIPT ZONE | DELIVERY ZONE 0 | L | 1 | 2 | 3 | 4 | 5 | 6 |
|---|---|---|---|---|---|---|---|---|
| 0 | $0.0035 | | $0.0134 | $0.0208 | $0.0258 | $0.0312 | $0.0355 | $0.0426 |
| L | | $0.0012 | | | | | | |
| 1 | $0.0047 | | $0.0094 | $0.0172 | $0.0211 | $0.0262 | $0.0320 | $0.0368 |
| 2 | $0.0208 | | $0.0101 | $0.0011 | $0.0031 | $0.0068 | $0.0124 | $0.0169 |
| 3 | $0.0258 | | $0.0211 | $0.0031 | $0.0000 | $0.0099 | $0.0147 | $0.0196 |
| 4 | $0.0312 | | $0.0242 | $0.0100 | $0.0122 | $0.0032 | $0.0056 | $0.0106 |
| 5 | $0.0355 | | $0.0320 | $0.0124 | $0.0147 | $0.0056 | $0.0055 | $0.0073 |
| 6 | $0.0426 | | $0.0368 | $0.0169 | $0.0196 | $0.0098 | $0.0041 | $0.0015 |

1/ Included in the above F&LR is the Losses component of the F&LR equal to 0.21%.
2/ For service that is rendered entirely by displacement and for gas scheduled and allocated for receipt at the Dracut, Massachusetts receipt point, Shipper shall render only the quantity of gas associated with Losses of 0.21%.
3/ The F&LR's and EPCR's listed above are applicable to FT-A, FT-BH, FT-G, FT-GS, NET, NET-284 and IT.
4/ The F&LR's and EPCR's determined pursuant to Article XXXVII of the General Terms and Conditions.

RATES PER DEKATHERM

FIRM STORAGE SERVICE
RATE SCHEDULE FS

| Rate Schedule and Rate | Base Tariff Rate | Max Tariff Rate | F&LR 2/, 3/ | EPCR 2/ |
|---|---|---|---|---|
| FIRM STORAGE SERVICE (FS) - PRODUCTION AREA | | | | |
| Deliverability Rate | $2.8100 | $2.8100 1/ | | |
| Space Rate | $0.0286 | $0.0286 1/ | | |
| Injection Rate | $0.0073 | $0.0073 | 1.91% | $0.0000 |
| Withdrawal Rate | $0.0073 | $0.0073 | | |
| Overrun Rate | $0.3372 | $0.3372 1/ | | |
| FIRM STORAGE SERVICE (FS) - MARKET AREA | | | | |
| Deliverability Rate | $1.5400 | $1.5400 1/ | | |
| Space Rate | $0.0211 | $0.0211 1/ | | |
| Injection Rate | $0.0087 | $0.0087 | 1.91% | $0.0000 |
| Withdrawal Rate | $0.0087 | $0.0087 | | |
| Overrun Rate | $0.1848 | $0.1848 1/ | | |

1/ Includes a per Dth charge for the PCB Surcharge Adjustment per Article XXXII of the General Terms and Conditions of $0.000.
2/ The F&LR's and EPCR's determined pursuant to Article XXXVII of the General Terms and Conditions.
3/ The applicable F&LR pursuant to Article XXXVII of the General Terms and Conditions, associated with Losses is equal to 0.21%.

RATES PER DEKATHERM

INTERRUPTIBLE STORAGE SERVICE
RATE SCHEDULE IS

| Rate Schedule and Rate | Base Tariff Rate | Max Tariff Rate | F&LR 2/, 3/ | EPCR 2/ |
|---|---|---|---|---|
| **INTERRUPTIBLE STORAGE SERVICE (IS) - PRODUCTION AREA** | | | | |
| Space Rate | $0.1050 | $0.1050 1/ | | |
| Injection Rate | $0.0073 | $0.0073 | 1.91% | $0.0000 |
| Withdrawal Rate | $0.0073 | $0.0073 | | |
| **INTERRUPTIBLE STORAGE SERVICE (IS) - MARKET AREA** | | | | |
| Space Rate | $0.0846 | $0.0846 1/ | | |
| Injection Rate | $0.0087 | $0.0087 | 1.91% | $0.0000 |
| Withdrawal Rate | $0.0087 | $0.0087 | | |

1/ Includes a per Dth charge for the PCB Surcharge Adjustment per Article XXXII of the General Terms and Conditions of $0.0000.
2/ The F&LR's and EPCR's determined pursuant to Article XXXVII of the General Terms and Conditions.
3/ The applicable F&LR pursuant to Article XXXVII of the General Terms and Conditions associated with Losses is equal to 0.21%.

NET-284 RATE SCHEDULE (continued)

5. SHIPPERS

The Shippers to which this Rate Schedule is available, each Shipper's Transportation Quantity and the rate zone applicable to the transportation service provided by Transporter are as follows:

| Shipper | Transportation Quantity (Dth) | Rate Zones Receipt | Delivery |
|---|---|---|---|
| Bay State (from Granite) - Pleasant St. | 3,706 | 5 | 6 |
| Bay State (from Granite) - Agawam | 6,068 | 5 | 6 |
| Boston Gas d/b/a National Grid | 35,000 | 5 | 6 |
| Boston Gas d/b/a National Grid | 8,600 | 5 | 6 |
| Barclays Bank PLC | 14,010 | 5 | 6 |
| EnergyNorth Natural Gas, Inc. d/b/a National Grid | 4,000 | 5 | 6 |
| Essex Gas Company d/b/a National Grid | 2,000 | 5 | 6 |
| Iroquois Gas Transmission (Connecticut Natural, Yankee Gas) | 37,000 | 6 | 6 |
| Lockport Energy Associates | 13,184 | 1 | 5 |
| New York State Electric & Gas Corp | 14,816 | 1 | 5 |
| Northern Utilities (from Granite) Pleasant St. | 844 | 5 | 6 |
| Northern Utilities (from Granite) Agawam | 1,382 | 5 | 6 |
| The Narragansett Electric Company d/b/a National Grid | 1,000 | 5 | 6 |
| Yankee Gas Services Company (Wright) | 9,000 | 5 | 6 |
| Total | 150,610 | | |

Transportation Tolls
Approved Mainline Interim Tolls effective January 1, 2012

**System Average Unit Cost of Transportation**

| Line No | Particulars | Net Revenue Requirement ($000's) | Allocation Base | | Annual Unit Cost | | Daily Unit Cost | |
|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | | (d) | | (e) | |
| 1 | Fixed Energy | 76,148 | 3,938,676 | GJ | 19.3333983638 | $/GJ | 0.0529682147 | $/GJ |
| 2 | Transmission - Fixed | 1,169,509 | 4,862,440,154 | GJ-KM | 0.2405190214 | $/GJ-Km | 0.0006589562 | $/GJ-Km |
| 3 | Transmission - Variable | 48,954 | 1,053,676,682,785 | GJ-KM | - | $/GJ-Km | 0.0000464601 | $/GJ-Km |

**Storage Transportation Service**

| Line No | Particulars | Demand Toll ($/GJ/Month) | Commodity Toll ($/GJ) | Daily Equivalent ($/GJ) |
|---|---|---|---|---|
| | (a) | (b) | (c) | (d) |
| 4 | Centram MDA | 4.46187 | 0.00722 | 0.1539 |
| 5 | Union WDA | 31.41463 | 0.06896 | 1.1018 |
| 6 | Union NDA | 12.30579 | 0.02546 | 0.4300 |
| 7 | Union EDA | 8.00131 | 0.01505 | 0.2781 |
| 8 | KPUC EDA | 7.70246 | 0.01412 | 0.2674 |
| 9 | GMIT EDA | 14.16801 | 0.02929 | 0.4951 |
| 10 | Enbridge CDA | 1.69730 | 0.00024 | 0.0560 |
| 11 | Enbridge EDA | 4.84530 | 0.00757 | 0.1669 |
| 12 | Cornwall | 10.94987 | 0.02165 | 0.3816 |
| 13 | Philipsburg | 14.44301 | 0.02974 | 0.5046 |

**Firm Transportation - Short Notice**

| Line No | Particulars | Demand Toll ($/GJ/Month) | Commodity Toll ($/GJ) | Daily Equivalent *(1) ($/GJ) |
|---|---|---|---|---|
| | (a) | (b) | (c) | (d) |
| 14 | Kirkwall to Thorold - CDA | 3.87336 | 0.00487 | 0.1322 |
| 15 | Parkway to Goreway - CDA | 2.39507 | 0.00144 | 0.0802 |
| 16 | Parkway to Victoria Square #2 CDA | 3.17490 | 0.00326 | 0.1077 |
| 17 | Parkway to Schomberg #2 CDA | 3.12397 | 0.00314 | 0.1059 |

*(1) The Daily Equivalent Toll represents the minimum bid floor for ST-SN service.

**Delivery Pressure**

| Line No | Particulars | Demand Toll ($/GJ/Month) | Commodity Toll ($/GJ) | Daily Equivalent *(2) ($/GJ) |
|---|---|---|---|---|
| | (a) | (b) | (c) | (d) |
| 18 | Emerson - 1 (Viking) | 0.09571 | 0.00000 | 0.0032 |
| 19 | Emerson - 2 (Great Lakes) | 0.14114 | 0.00000 | 0.0046 |
| 20 | Dawn | 0.08038 | 0.00000 | 0.0026 |
| 21 | Niagara Falls | 0.59443 | 0.00000 | 0.0195 |
| 22 | Iroquois | 1.03785 | 0.00000 | 0.0341 |
| 23 | Chippawa | 1.03444 | 0.00000 | 0.0340 |
| 24 | East Hereford | 4.54054 | 0.03226 | 0.1815 |

*(2) The Demand Daily Equivalent Toll is only applicable to STS Injections, IT, Diversions and STFT.

**Union Dawn Receipt Point Surcharge**

| Line No | Particulars | Demand Toll ($/GJ/Month) | Commodity Toll ($/GJ) | Daily Equivalent ($/GJ) |
|---|---|---|---|---|
| | (a) | (b) | (c) | (d) |
| 25 | Union Dawn Receipt Point Surcharge | 0.09828 | 0.00000 | 0.0032 |

FT, STFT and Interruptible Transportation Tolls
Approved Mainline Interim Tolls effective January 1, 2012

| Line No. | Receipt Point | Delivery point | Demand Toll ($/GJ/MO) | Commodity Toll ($/GJ) | (FT, STFT Minimum Tolls)[ii] (100% LF FT Tolls) ($/GJ) | IT Bid Floor (110% FT Tolls) ($/GJ) |
|---|---|---|---|---|---|---|
| 1 | Union Parkway Belt | Centrat MDA | 40.47278 | 0.09008 | 1.4207 | 1.5628 |
| 2 | Union Parkway Belt | Union WDA | 31.16449 | 0.06841 | 1.0930 | 1.2023 |
| 3 | Union Parkway Belt | Nipigon WDA | 27.37231 | 0.05971 | 0.9596 | 1.0556 |
| 4 | Union Parkway Belt | Union NDA | 12.30620 | 0.02546 | 0.4301 | 0.4731 |
| 5 | Union Parkway Belt | Calstock NDA | 20.74300 | 0.04435 | 0.7264 | 0.7990 |
| 6 | Union Parkway Belt | Tunis NDA | 15.52374 | 0.03225 | 0.5427 | 0.5970 |
| 7 | Union Parkway Belt | GMIT NDA | 11.69247 | 0.02319 | 0.4076 | 0.4484 |
| 8 | Union Parkway Belt | Union SSMDA | 18.35505 | 0.03881 | 0.6423 | 0.7065 |
| 9 | Union Parkway Belt | Union NCDA | 5.29747 | 0.00861 | 0.1828 | 0.2011 |
| 10 | Union Parkway Belt | Union CDA | 2.07011 | 0.00053 | 0.0686 | 0.0755 |
| 11 | Union Parkway Belt | Enbridge CDA | 3.14523 | 0.00350 | 0.1069 | 0.1176 |
| 12 | Union Parkway Belt | Union EDA | 8.15784 | 0.01535 | 0.2836 | 0.3120 |
| 13 | Union Parkway Belt | Enbridge EDA | 10.97773 | 0.02175 | 0.3827 | 0.4210 |
| 14 | Union Parkway Belt | GMIT EDA | 14.26643 | 0.02945 | 0.4985 | 0.5484 |
| 15 | Union Parkway Belt | KPUC EDA | 7.70246 | 0.01412 | 0.2673 | 0.2940 |
| 16 | Union Parkway Belt | North Bay Junction | 8.81626 | 0.01670 | 0.3065 | 0.3372 |
| 17 | Union Parkway Belt | Enbridge SWDA | 6.15853 | 0.01054 | 0.2130 | 0.2343 |
| 18 | Union Parkway Belt | Union SWDA | 6.36578 | 0.01079 | 0.2201 | 0.2421 |
| 19 | Union Parkway Belt | Spruce | 40.47278 | 0.09008 | 1.4207 | 1.5628 |
| 20 | Union Parkway Belt | Emerson 1 | 38.02790 | 0.08441 | 1.3346 | 1.4681 |
| 21 | Union Parkway Belt | Emerson 2 | 38.02790 | 0.08441 | 1.3346 | 1.4681 |
| 22 | Union Parkway Belt | St. Clair | 6.63616 | 0.01165 | 0.2299 | 0.2529 |
| 23 | Union Parkway Belt | Dawn Export | 6.15853 | 0.01054 | 0.2130 | 0.2343 |
| 24 | Union Parkway Belt | Kirkwall | 2.37697 | 0.00178 | 0.0799 | 0.0879 |
| 25 | Union Parkway Belt | Niagara Falls | 4.27106 | 0.00617 | 0.1466 | 0.1613 |
| 26 | Union Parkway Belt | Chippawa | 4.31896 | 0.00628 | 0.1483 | 0.1631 |
| 27 | Union Parkway Belt | Iroquois | 10.16778 | 0.01983 | 0.3541 | 0.3895 |
| 28 | Union Parkway Belt | Cornwall | 11.01681 | 0.02180 | 0.3840 | 0.4224 |
| 29 | Union Parkway Belt | Napierville | 14.09626 | 0.02894 | 0.4923 | 0.5415 |
| 30 | Union Parkway Belt | Philipsburg | 14.44621 | 0.02975 | 0.5047 | 0.5552 |
| 31 | Union Parkway Belt | East Hereford | 18.15642 | 0.03835 | 0.6353 | 0.6988 |
| 32 | Union Parkway Belt | Welwyn | 46.28071 | 0.10354 | 1.6251 | 1.7876 |
| 33 | Union NCDA | Empress | 56.87397 | 0.12803 | 1.9978 | 2.1976 |
| 34 | Union NCDA | Transgas SSDA | 48.16057 | 0.10875 | 1.6922 | 1.8614 |
| 35 | Union NCDA | Centram SSDA | 44.61612 | 0.09962 | 1.5664 | 1.7230 |
| 36 | Union NCDA | Centram MDA | 39.26096 | 0.08782 | 1.3786 | 1.5165 |
| 37 | Union NCDA | Centrat MDA | 36.78642 | 0.08147 | 1.2909 | 1.4200 |
| 38 | Union NCDA | Union WDA | 27.47814 | 0.05979 | 0.9632 | 1.0595 |
| 39 | Union NCDA | Nipigon WDA | 23.68595 | 0.05110 | 0.8298 | 0.9128 |
| 40 | Union NCDA | Union NDA | 8.61984 | 0.01685 | 0.3003 | 0.3303 |
| 41 | Union NCDA | Calstock NDA | 17.05665 | 0.03574 | 0.5965 | 0.6562 |
| 42 | Union NCDA | Tunis NDA | 11.83738 | 0.02364 | 0.4128 | 0.4541 |
| 43 | Union NCDA | GMIT NDA | 8.00632 | 0.01458 | 0.2778 | 0.3056 |
| 44 | Union NCDA | Union SSMDA | 22.04140 | 0.04742 | 0.7720 | 0.8492 |
| 45 | Union NCDA | Union NCDA | 1.61112 | 0.00000 | 0.0530 | 0.0583 |
| 46 | Union NCDA | Union CDA | 5.75646 | 0.00915 | 0.1985 | 0.2184 |
| 47 | Union NCDA | Enbridge CDA | 5.20928 | 0.00836 | 0.1797 | 0.1977 |
| 48 | Union NCDA | Union EDA | 9.89018 | 0.01945 | 0.3447 | 0.3792 |
| 49 | Union NCDA | Enbridge EDA | 11.86043 | 0.02382 | 0.4137 | 0.4551 |
| 50 | Union NCDA | GMIT EDA | 15.84503 | 0.03319 | 0.5541 | 0.6095 |
| 51 | Union NCDA | KPUC EDA | 9.52199 | 0.01840 | 0.3315 | 0.3647 |
| 52 | Union NCDA | North Bay Junction | 5.12991 | 0.00809 | 0.1768 | 0.1945 |
| 53 | Union NCDA | Enbridge SWDA | 9.84488 | 0.01915 | 0.3429 | 0.3772 |
| 54 | Union NCDA | Union SWDA | 10.05213 | 0.01940 | 0.3499 | 0.3849 |
| 55 | Union NCDA | Spruce | 36.78642 | 0.08147 | 1.2909 | 1.4200 |
| 56 | Union NCDA | Emerson 1 | 39.62795 | 0.08806 | 1.3909 | 1.5300 |
| 57 | Union NCDA | Emerson 2 | 39.62795 | 0.08806 | 1.3909 | 1.5300 |
| 58 | Union NCDA | St. Clair | 10.32252 | 0.02026 | 0.3597 | 0.3957 |
| 59 | Union NCDA | Dawn Export | 9.84488 | 0.01915 | 0.3429 | 0.3772 |
| 60 | Union NCDA | Kirkwall | 6.06332 | 0.01039 | 0.2097 | 0.2307 |
| 61 | Union NCDA | Niagara Falls | 7.95741 | 0.01478 | 0.2764 | 0.3040 |
| 62 | Union NCDA | Chippawa | 8.00531 | 0.01489 | 0.2781 | 0.3059 |
| 63 | Union NCDA | Iroquois | 11.79008 | 0.02368 | 0.4113 | 0.4524 |
| 64 | Union NCDA | Cornwall | 12.59522 | 0.02554 | 0.4396 | 0.4836 |
| 65 | Union NCDA | Napierville | 15.67466 | 0.03268 | 0.5480 | 0.6028 |
| 66 | Union NCDA | Philipsburg | 16.02462 | 0.03349 | 0.5603 | 0.6163 |
| 67 | Union NCDA | East Hereford | 19.73483 | 0.04209 | 0.6909 | 0.7600 |
| 68 | Union NCDA | Welwyn | 44.61612 | 0.09962 | 1.5664 | 1.7230 |
| 69 | Union SSMDA | Empress | 45.07892 | 0.10076 | 1.5828 | 1.7411 |
| 70 | Union SSMDA | Transgas SSDA | 36.36551 | 0.08147 | 1.2771 | 1.4048 |
| 71 | Union SSMDA | Centram SSDA | 32.82107 | 0.07234 | 1.1513 | 1.2664 |
| 72 | Union SSMDA | Centram MDA | 27.43845 | 0.06048 | 0.9626 | 1.0589 |
| 73 | Union SSMDA | Centrat MDA | 27.41259 | 0.05981 | 0.9610 | 1.0571 |
| 74 | Union SSMDA | Union WDA | 37.50337 | 0.08335 | 1.3164 | 1.4480 |
| 75 | Union SSMDA | Nipigon WDA | 40.51306 | 0.09017 | 1.4221 | 1.5643 |
| 76 | Union SSMDA | Union NDA | 29.05013 | 0.06427 | 1.0194 | 1.1213 |
| 77 | Union SSMDA | Calstock NDA | 37.48693 | 0.08316 | 1.3156 | 1.4472 |
| 78 | Union SSMDA | Tunis NDA | 32.26767 | 0.07106 | 1.1320 | 1.2452 |

**TRANSCANADA FUEL RATIOS**

### November 2011

| Pressure Point | Pressure (%) |
|---|---|
| Chippawa | 0.83 |
| Emerson 1 | 0.13 |
| Emerson 2 | 0.13 |
| Iroquois | 0.69 |
| Niagara Falls | 0.00 |
| | |

| Receipt | Delivery | Min IT Bid Toll | Fuel Ratio (%) (with pressure) | Fuel Ratio (%) (without pressure) |
|---|---|---|---|---|
| Union Parkway Belt | Iroquois | **0.3895** | **1.02** | 0.33 |

### February 2012

| Pressure Point | Pressure (%) |
|---|---|
| Chippawa | 0.83 |
| Emerson 1 | 0.13 |
| Emerson 2 | 0.13 |
| Iroquois | 0.69 |
| Niagara Falls | 0.00 |
| | |

| Receipt | Delivery | Min IT Bid Toll | Fuel Ratio (%) (with pressure) | Fuel Ratio (%) (without pressure) |
|---|---|---|---|---|
| Union Parkway Belt | Iroquois | **0.3895** | **1.30** | 0.61 |

### December 2011

| Pressure Point | Pressure (%) |
|---|---|
| Chippawa | 0.83 |
| Emerson 1 | 0.13 |
| Emerson 2 | 0.13 |
| Iroquois | 0.69 |
| Niagara Falls | 0.00 |
| | |

| Receipt | Delivery | Min IT Bid Toll | Fuel Ratio (%) (with pressure) | Fuel Ratio (%) (without pressure) |
|---|---|---|---|---|
| Union Parkway Belt | Iroquois | **0.3895** | **1.09** | 0.40 |

### March 2012

| Pressure Point | Pressure (%) |
|---|---|
| Chippawa | 0.83 |
| Emerson 1 | 0.13 |
| Emerson 2 | 0.13 |
| Iroquois | 0.69 |
| Niagara Falls | 0.00 |
| | |

| Receipt | Delivery | Min IT Bid Toll | Fuel Ratio (%) (with pressure) | Fuel Ratio (%) (without pressure) |
|---|---|---|---|---|
| Union Parkway Belt | Iroquois | **0.3895** | **1.00** | 0.31 |

### January 2012

| Pressure Point | Pressure (%) |
|---|---|
| Chippawa | 0.83 |
| Emerson 1 | 0.13 |
| Emerson 2 | 0.13 |
| Iroquois | 0.69 |
| Niagara Falls | 0.00 |
| | |

| Receipt | Delivery | Min IT Bid Toll | Fuel Ratio (%) (with pressure) | Fuel Ratio (%) (without pressure) |
|---|---|---|---|---|
| Union Parkway Belt | Iroquois | **0.3895** | **1.36** | 0.67 |

### April 2012

| Pressure Point | Pressure (%) |
|---|---|
| Chippawa | 0.83 |
| Emerson 1 | 0.13 |
| Emerson 2 | 0.13 |
| Iroquois | 0.69 |
| Niagara Falls | 0.00 |
| | |

| Receipt | Delivery | Min IT Bid Toll | Fuel Ratio (%) (with pressure) | Fuel Ratio (%) (without pressure) |
|---|---|---|---|---|
| Union Parkway Belt | Iroquois | **0.3895** | **0.88** | 0.19 |

**ENERGY NORTH NATURAL GAS, INC.**

**Peak 2012 - 2013 Winter Cost of Gas Filing**
**NYMEX Futures @ Henry Hub and Hedged Contracts**

| For Month of: | Reference | Nov-12 | Dec-12 | Jan-13 | Feb-13 | Mar-13 | Apr-13 | Peak Strip Average |
|---|---|---|---|---|---|---|---|---|
| (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) |
| **I. NYMEX Opening Prices as of:** | | | | | | | | |
| Opening Prices (15 day average) | | 3.1057 | 3.3715 | 3.5012 | 3.5151 | 3.4954 | 3.4754 | $ 3.4107 |
| NYMEX | ln 201 | 3.1057 | 3.3715 | 3.5012 | 3.5151 | 3.4954 | 3.4754 | $ 3.4107 |
| | | | | | | | | |
| **II. Development of Hedging Costs and Savings** | | | | | | | | |
| **TGP (Direct) Volumes** | | | | | | | | Total |
| Hedged Volumes (Dth) | ln 83 | 400,000 | 480,000 | 480,000 | 520,000 | 650,000 | 400,000 | 2,930,000 |
| Market Priced Volumes (Dth) | | 646,969 | 536,554 | 641,967 | 528,432 | 335,754 | 617,632 | 3,307,308 |
| Total Volumes (Dth) | Sch 6, lns 63 - 68 / 10 | 1,046,969 | 1,016,554 | 1,121,967 | 1,048,432 | 985,754 | 1,017,632 | 6,237,308 |
| | | | | | | | | Weighted Average |
| Hedge Price | ln 170 | $ 3.9599 | $ 4.0771 | $ 4.1587 | $ 4.1362 | $ 4.1431 | $ 3.9796 | $ 4.0863 |
| NYMEX Price | ln 10 | $ 3.1057 | $ 3.3715 | $ 3.5012 | $ 3.5151 | $ 3.4954 | $ 3.4754 | $ 3.4236 |
| Hedged Volumes at Hedged Price | ln 23 * ln 28 | $ 1,583,950 | $ 1,957,010 | $ 1,996,170 | $ 2,150,836 | $ 2,692,993 | $ 1,591,834 | $ 11,972,792 |
| Less Hedged Volumes at NYMEX | ln 24 * ln 29 | 1,242,267 | 1,618,304 | 1,680,576 | 1,827,835 | 2,272,010 | 1,390,160 | 10,031,151 |
| Hedge Contract (Savings)/Loss | ln 31 - ln 32 | $ 341,683 | $ 338,706 | $ 315,594 | $ 323,001 | $ 420,983 | $ 201,674 | $ 1,941,641 |
| Total Financial Hedge | ln 23 | 4,000,000 | 4,800,000 | 4,800,000 | 5,200,000 | 6,500,000 | 4,000,000 | 29,300,000 |
| Total Underground Storage | Sch 6, Ln 77 | 1,223,530 | 4,811,730 | 5,793,480 | 4,971,120 | 3,670,590 | 52,360 | 20,522,810 |
| Sub Total | | 5,223,530 | 9,611,730 | 10,593,480 | 10,171,120 | 10,170,590 | 4,052,360 | 49,822,810 |
| Total Throughput | Sch 6, ln 92 | 9,922,220 | 15,075,830 | 17,807,020 | 15,547,840 | 13,617,450 | 8,018,010 | 79,988,370 |
| Hedge Percentage | ln 38 / ln 39 | 53% | 64% | 59% | 65% | 75% | 51% | 62% |

**ENERGY NORTH NATURAL GAS, INC.**

**Peak 2012 - 2013 Winter Cost of Gas Filing**
**NYMEX Futures @ Henry Hub and Hedged Contracts**

| For Month of: | | | | Reference | Nov-12 | Dec-12 | Jan-13 | Feb-13 | Mar-13 | Apr-13 | Peak Strip Average |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | | | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) |
| Hedged Volumes (Dth) | | | | | | | | | | | |
| Hedge # | 1 | Trade Date | 10-Jun-11 | Swaps | [redacted] | | | | | | |
| Hedge # | 2 | Trade Date | 24-Jun-11 | Swaps | | | | | | | |
| Hedge # | 3 | Trade Date | 08-Jul-11 | Swaps | | | | | | | |
| Hedge # | 4 | Trade Date | 22-Jul-11 | Swaps | | | | | | | |
| Hedge # | 5 | Trade Date | 05-Aug-11 | Swaps | | | | | | | |
| Hedge # | 6 | Trade Date | 18-Aug-11 | Swaps | | | | | | | |
| Hedge # | 7 | Trade Date | 09-Sep-11 | Swaps | | | | | | | |
| Hedge # | 8 | Trade Date | 23-Sep-11 | Swaps | | | | | | | |
| Hedge # | 9 | Trade Date | 05-Dec-11 | Swaps | | | | | | | |
| Hedge # | 10 | Trade Date | 16-Dec-11 | Swaps | | | | | | | |
| Hedge # | 11 | Trade Date | 06-Jan-12 | Swaps | | | | | | | |
| Hedge # | 12 | Trade Date | 27-Jan-12 | Swaps | | | | | | | |
| Hedge # | 13 | Trade Date | 10-Feb-12 | Swaps | | | | | | | |
| Hedge # | 14 | Trade Date | 24-Feb-12 | Swaps | | | | | | | |
| Hedge # | 15 | Trade Date | 08-Jun-12 | Swaps | | | | | | | |
| Hedge # | 16 | Trade Date | 21-Jun-12 | Swaps | | | | | | | |
| Hedge # | 17 | Trade Date | 05-Jul-12 | Swaps | | | | | | | |
| Hedge # | 18 | Trade Date | 20-Jul-12 | Swaps | | | | | | | |
| Hedge # | 19 | Trade Date | | Swaps | | | | | | | |
| Hedge # | 20 | Trade Date | | Swaps | | | | | | | |
| Hedge # | 21 | Trade Date | | Swaps | | | | | | | |
| Hedge # | 22 | Trade Date | | Swaps | | | | | | | |
| Hedge # | 23 | Trade Date | | Swaps | | | | | | | |
| Hedge # | 24 | Trade Date | | Swaps | | | | | | | |
| Hedge # | 25 | Trade Date | | Swaps | | | | | | | |
| Hedge # | 26 | Trade Date | | Swaps | | | | | | | |
| Hedge # | 27 | Trade Date | | Swaps | | | | | | | |
| Hedge # | 28 | Trade Date | | Swaps | | | | | | | |
| Hedge # | 29 | Trade Date | | Swaps | | | | | | | |
| Hedge # | 30 | Trade Date | | Swaps | | | | | | | |
| Subtotal Hedge Volumes | | | | | 280,000 | 320,000 | 330,000 | 360,000 | 430,000 | 290,000 | 2,010,000 |
| Remaining | | | | | 120,000 | 160,000 | 150,000 | 160,000 | 220,000 | 110,000 | 920,000 |
| Total Volumes | | | | | 400,000 | 480,000 | 480,000 | 520,000 | 650,000 | 400,000 | 2,930,000 |

REDACTED

**ENERGY NORTH NATURAL GAS, INC.**

**Peak 2012 - 2013 Winter Cost of Gas Filing**
**NYMEX Futures @ Henry Hub and Hedged Contracts**

| | | | | | | Nov-12 | Dec-12 | Jan-13 | Feb-13 | Mar-13 | Apr-13 | Peak Strip Average |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| For Month of: | | | | Reference | | | | | | | | |
| | (a) | | | (b) | | (c) | (d) | (e) | (f) | (g) | (h) | (i) |
| Strike Price | | | | | | | | | | | | Weighted Average |
| Hedge # | 1 | Trade Date | 10-Jun-11 | Swaps | | [redacted] | | | | | | |
| Hedge # | 2 | Trade Date | 24-Jun-11 | Swaps | | | | | | | | |
| Hedge # | 3 | Trade Date | 08-Jul-11 | Swaps | | | | | | | | |
| Hedge # | 4 | Trade Date | 22-Jul-11 | Swaps | | | | | | | | |
| Hedge # | 5 | Trade Date | 05-Aug-11 | Swaps | | | | | | | | |
| Hedge # | 6 | Trade Date | 18-Aug-11 | Swaps | | | | | | | | |
| Hedge # | 7 | Trade Date | 09-Sep-11 | Swaps | | | | | | | | |
| Hedge # | 8 | Trade Date | 23-Sep-11 | Swaps | | | | | | | | |
| Hedge # | 9 | Trade Date | 05-Dec-11 | Swaps | | | | | | | | |
| Hedge # | 10 | Trade Date | 16-Dec-11 | Swaps | | | | | | | | |
| Hedge # | 11 | Trade Date | 06-Jan-12 | Swaps | | | | | | | | |
| Hedge # | 12 | Trade Date | 27-Jan-12 | Swaps | | | | | | | | |
| Hedge # | 13 | Trade Date | 10-Feb-12 | Swaps | | | | | | | | |
| Hedge # | 14 | Trade Date | 24-Feb-12 | Swaps | | | | | | | | |
| Hedge # | 15 | Trade Date | 08-Jun-12 | Swaps | | | | | | | | |
| Hedge # | 16 | Trade Date | 21-Jun-12 | Swaps | | | | | | | | |
| Hedge # | 17 | Trade Date | 05-Jul-12 | Swaps | | | | | | | | |
| Hedge # | 18 | Trade Date | 20-Jul-12 | Swaps | | | | | | | | |
| Hedge # | 19 | Trade Date | 00-Jan-00 | Swaps | | | | | | | | |
| Hedge # | 20 | Trade Date | 00-Jan-00 | Swaps | | | | | | | | |
| Hedge # | 21 | Trade Date | 00-Jan-00 | Swaps | | | | | | | | |
| Hedge # | 22 | Trade Date | 00-Jan-00 | Swaps | | | | | | | | |
| Hedge # | 23 | Trade Date | 00-Jan-00 | Swaps | | | | | | | | |
| Hedge # | 24 | Trade Date | 00-Jan-00 | Swaps | | | | | | | | |
| Hedge # | 25 | Trade Date | 00-Jan-00 | Swaps | | | | | | | | |
| Hedge # | 26 | Trade Date | | Swaps | | | | | | | | |
| Hedge # | 27 | Trade Date | | Swaps | | | | | | | | |
| Hedge # | 28 | Trade Date | | Swaps | | | | | | | | |
| Hedge # | 29 | Trade Date | | Swaps | | | | | | | | |
| Hedge # | 30 | Trade Date | | Swaps | | | | | | | | |
| Subtotal Weigthed Average Hedge Prices | | | | | | $4.3260 | $4.4299 | $4.4575 | $4.4123 | $4.4744 | $4.1708 | 4.3890 |
| NYMEX | | | | | | $3.1057 | $3.3715 | $3.5012 | $3.5151 | $3.4954 | $3.4754 | 3.4250 |

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00000117

**ENERGY NORTH NATURAL GAS, INC.**

**Peak 2012 - 2013 Winter Cost of Gas Filing**
**NYMEX Futures @ Henry Hub and Hedged Contracts**

| For Month of: | (a) | | Reference (b) | Nov-12 (c) | Dec-12 (d) | Jan-13 (e) | Feb-13 (f) | Mar-13 (g) | Apr-13 (h) | Peak Strip Average (i) |
|---|---|---|---|---|---|---|---|---|---|---|
| Hedge Dollars | | | | | | | | | | |
| Hedge # 1 | Trade Date | 10-Jun-11 | Swaps | [redacted] | | | | | | |
| Hedge # 2 | Trade Date | 24-Jun-11 | Swaps | | | | | | | |
| Hedge # 3 | Trade Date | 08-Jul-11 | Swaps | | | | | | | |
| Hedge # 4 | Trade Date | 22-Jul-11 | Swaps | | | | | | | |
| Hedge # 5 | Trade Date | 05-Aug-11 | Swaps | | | | | | | |
| Hedge # 6 | Trade Date | 18-Aug-11 | Swaps | | | | | | | |
| Hedge # 7 | Trade Date | 09-Sep-11 | Swaps | | | | | | | |
| Hedge # 8 | Trade Date | 23-Sep-11 | Swaps | | | | | | | |
| Hedge # 9 | Trade Date | 05-Dec-11 | Swaps | | | | | | | |
| Hedge # 10 | Trade Date | 16-Dec-11 | Swaps | | | | | | | |
| Hedge # 11 | Trade Date | 06-Jan-12 | Swaps | | | | | | | |
| Hedge # 12 | Trade Date | 27-Jan-12 | Swaps | | | | | | | |
| Hedge # 13 | Trade Date | 10-Feb-12 | Swaps | | | | | | | |
| Hedge # 14 | Trade Date | 24-Feb-12 | Swaps | | | | | | | |
| Hedge # 15 | Trade Date | 08-Jun-12 | Swaps | | | | | | | |
| Hedge # 16 | Trade Date | 21-Jun-12 | Swaps | | | | | | | |
| Hedge # 17 | Trade Date | 05-Jul-12 | Swaps | | | | | | | |
| Hedge # 18 | Trade Date | 20-Jul-12 | Swaps | | | | | | | |
| Hedge # 19 | Trade Date | 00-Jan-00 | Swaps | | | | | | | |
| Hedge # 20 | Trade Date | 00-Jan-00 | Swaps | | | | | | | |
| Hedge # 21 | Trade Date | 00-Jan-00 | Swaps | | | | | | | |
| Hedge # 22 | Trade Date | 00-Jan-00 | Swaps | | | | | | | |
| Hedge # 23 | Trade Date | 00-Jan-00 | Swaps | | | | | | | |
| Hedge # 24 | Trade Date | 00-Jan-00 | Swaps | | | | | | | |
| Hedge # 25 | Trade Date | 00-Jan-00 | Swaps | | | | | | | |
| Hedge # 26 | Trade Date | 00-Jan-00 | Swaps | | | | | | | |
| Hedge # 27 | Trade Date | 00-Jan-00 | Swaps | | | | | | | |
| Hedge # 28 | Trade Date | 00-Jan-00 | Swaps | | | | | | | |
| Hedge # 29 | Trade Date | 00-Jan-00 | Swaps | | | | | | | |
| Hedge # 30 | Trade Date | 00-Jan-00 | Swaps | | | | | | | |
| Subtotal Hedge Dollars | | | | $1,211,270 | $1,417,575 | $1,470,990 | $1,588,425 | $1,924,005 | $1,209,540 | $8,821,805 |
| Remaining | | | | 372,680 | 539,435 | 525,180 | 562,411 | 768,988 | 382,294 | 3,150,987 |
| Target Hedged Dollars | | | | $1,583,950 | $1,957,010 | $1,996,170 | $2,150,836 | $2,692,993 | $1,591,834 | $11,972,792 |
| Weighted Average Hedged Cost per Unit | | | | $3.9599 | $4.0771 | $4.1587 | $4.1362 | $4.1431 | $3.9796 | $4.0863 |

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**ENERGY NORTH NATURAL GAS, INC.**

**Peak 2012 - 2013 Winter Cost of Gas Filing**

**NYMEX Futures @ Henry Hub and Hedged Contracts**

| For Month of: | Reference | | Nov-12 | Dec-12 | Jan-13 | Feb-13 | Mar-13 | Apr-13 | Peak Strip Average |
|---|---|---|---|---|---|---|---|---|---|
| (a) | (b) | | (c) | (d) | (e) | (f) | (g) | (h) | (i) |
| NYMEX Settlement - 15 Day Average | | | | | | | | | |
| | Days | Date | | | | | | | |
| | 1 | 30-Jul | 3.3700 | 3.6020 | 3.7140 | 3.7270 | 3.6970 | 3.6650 | |
| | 2 | 31-Jul | 3.3480 | 3.5790 | 3.6900 | 3.7020 | 3.6730 | 3.6400 | |
| | 3 | 01-Aug | 3.2970 | 3.5400 | 3.6530 | 3.6640 | 3.6370 | 3.6070 | |
| | 4 | 02-Aug | 3.0660 | 3.3230 | 3.4510 | 3.4660 | 3.4420 | 3.4200 | |
| | 5 | 03-Aug | 3.0220 | 3.2770 | 3.4090 | 3.4230 | 3.4010 | 3.3820 | |
| | | 04-Aug | | | | | | | |
| | | 05-Aug | | | | | | | |
| | 6 | 06-Aug | 3.0630 | 3.3230 | 3.4540 | 3.4680 | 3.4470 | 3.4300 | |
| | 7 | 07-Aug | 3.1500 | 3.4090 | 3.5370 | 3.5510 | 3.5320 | 3.5100 | |
| | 8 | 08-Aug | 3.1570 | 3.4250 | 3.5560 | 3.5710 | 3.5570 | 3.5410 | |
| | 9 | 09-Aug | 3.1560 | 3.4200 | 3.5570 | 3.5700 | 3.5530 | 3.5340 | |
| | 10 | 10-Aug | 3.0270 | 3.3110 | 3.4530 | 3.4690 | 3.4560 | 3.4390 | |
| | | 11-Aug | | | | | | | |
| | | 12-Aug | | | | | | | |
| | 11 | 13-Aug | 2.9880 | 3.2760 | 3.4140 | 3.4280 | 3.4140 | 3.3970 | |
| | 12 | 14-Aug | 3.0660 | 3.3430 | 3.4730 | 3.4850 | 3.4690 | 3.4520 | |
| | 13 | 15-Aug | 2.9810 | 3.2720 | 3.4090 | 3.4230 | 3.4080 | 3.3940 | |
| | 14 | 16-Aug | 2.9490 | 3.2370 | 3.3730 | 3.3870 | 3.3710 | 3.3590 | |
| | 15 | 17-Aug | 2.9450 | 3.2350 | 3.3750 | 3.3920 | 3.3740 | 3.3610 | |
| | | 18-Aug | | | | | | | |
| | | 19-Aug | | | | | | | |
| | | 20-Aug | | | | | | | |
| | | 21-Aug | | | | | | | |
| | | 22-Aug | | | | | | | |
| | | 23-Aug | | | | | | | |
| | | 15 Day Average | 3.1057 | 3.3715 | 3.5012 | 3.5151 | 3.4954 | 3.4754 | |

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**ENERGY NORTH NATURAL GAS, INC.**

**Peak 2012 - 2013 Winter Cost of Gas Filing**
**Annual Bill Comparisons, Nov 11 - Apr 12 vs Nov 12 - Apr 13 - Residential Heating Rate R-3**

**November 1, 2012 - April 30, 2013**
**Residential Heating (R3)**

| | | | Nov-12 | Dec-12 | Jan-13 | Feb-13 | Mar-13 | Apr-13 | Winter Nov-Apr |
|---|---|---|---|---|---|---|---|---|---|
| **Typical Usage (Therms)** | | | 109 | 150 | 187 | 188 | 166 | 132 | 932 |
| | 07/01/2012 | 07/01/2011 | | | | | | | |
| **Winter:** | | | | | | | | | |
| Cust. Chg | $17.31 | $17.33 | $17.31 | $17.31 | $17.31 | $17.31 | $17.31 | $17.31 | $103.86 |
| Headblock | $0.2739 | $0.2741 | $27.39 | $27.39 | $27.39 | $27.39 | $27.39 | $27.39 | $164.34 |
| Tailblock | $0.2263 | $0.2265 | $2.04 | $11.32 | $19.69 | $19.91 | $14.94 | $7.24 | $75.13 |
| HB Threshold | 100 | 100 | | | | | | | |
| **Summer:** | | | | | | | | | |
| Cust. Chg | $17.31 | $17.33 | | | | | | | |
| Headblock | $0.2739 | $0.2741 | | | | | | | |
| Tailblock | $0.2263 | $0.2265 | | | | | | | |
| HB Threshold | 20 | 20 | | | | | | | |
| Total Base Rate Amount | | | $46.74 | $56.02 | $64.39 | $64.61 | $59.64 | $51.94 | $343.33 |
| CGA Rate - (Seasonal) | | | $0.6719 | $0.6719 | $0.6719 | $0.6719 | $0.6719 | $0.6719 | $0.6719 |
| CGA amount | | | $73.24 | $100.79 | $125.65 | $126.32 | $111.54 | $88.69 | $626.21 |
| LDAC | | | $0.0258 | $0.0258 | $0.0258 | $0.0258 | $0.0258 | $0.0258 | 0.0258 |
| LDAC amount | | | $2.81 | $3.87 | $4.82 | $4.85 | $4.28 | $3.41 | $24.05 |
| **Total Bill** | | | **$122.79** | **$160.67** | **$194.86** | **$195.78** | **$175.45** | **$144.04** | **$993.59** |

**May 1, 2012 - October 31, 2012**

| May-12 | Jun-12 | Jul-12 | Aug-12 | Sep-12 | Oct-12 | Summer May-Oct | Total Nov-Oct |
|---|---|---|---|---|---|---|---|
| 90 | 55 | 30 | 30 | 42 | 71 | 318 | 1,250 |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| $17.33 | $17.33 | $17.31 | $17.31 | $17.31 | $17.31 | $103.90 | $207.76 |
| $5.48 | $5.48 | $5.48 | $5.48 | $5.48 | $5.48 | $32.88 | $197.22 |
| $15.86 | $7.93 | $2.26 | $2.26 | $4.98 | $11.54 | $44.83 | $119.96 |
| | | | | | | | |
| $38.67 | $30.74 | $25.05 | $25.05 | $27.77 | $34.33 | $181.60 | $524.94 |
| | | | | | | | |
| $0.5118 | $0.4741 | $0.4695 | $0.5210 | $0.5403 | $0.5403 | $0.5123 | $0.6313 |
| $46.06 | $26.08 | $14.09 | $15.63 | $22.69 | $38.36 | $162.91 | $789.12 |
| | | | | | | | |
| $0.0693 | $0.0693 | $0.0693 | $0.0693 | $0.0693 | $0.0693 | $0.0693 | $0.0369 |
| $6.24 | $3.81 | $2.08 | $2.08 | $2.91 | $4.92 | $22.05 | $46.10 |
| | | | | | | | |
| **$90.97** | **$60.63** | **$41.22** | **$42.76** | **$53.37** | **$77.61** | **$366.56** | **$1,360.15** |

**November 1, 2011 - April 30, 2012**
**Residential Heating (R3)**

| | | | Nov-11 | Dec-11 | Jan-12 | Feb-12 | Mar-12 | Apr-12 | Winter Nov-Apr |
|---|---|---|---|---|---|---|---|---|---|
| **Typical Usage (Therms)** | | | 109 | 150 | 187 | 188 | 166 | 132 | 932 |
| **Winter:** | 07/01/2011 | 04/01/2011 | | | | | | | |
| Cust. Chg | $17.33 | $17.16 | $17.33 | $17.33 | $17.33 | $17.33 | $17.33 | $17.33 | $103.98 |
| Headblock | $0.2741 | $0.2714 | 27.41 | 27.41 | 27.41 | 27.41 | 27.41 | 27.41 | $164.46 |
| Tailblock | $0.2265 | $0.2243 | $2.04 | $11.33 | $19.71 | $19.93 | $14.95 | $7.25 | $75.20 |
| HB Threshold | 100 | 100 | | | | | | | |
| **Summer:** | | | | | | | | | |
| Cust. Chg | $17.33 | $17.16 | | | | | | | |
| Headblock | $0.2741 | $0.2714 | | | | | | | |
| Tailblock | $0.2265 | $0.2243 | | | | | | | |
| HB Threshold | 20 | 20 | | | | | | | |
| Total Base Rate Amount | | | $46.78 | $56.07 | $64.45 | $64.67 | $59.69 | $51.99 | $343.64 |
| CGA Rate - (Seasonal) | | | $0.7926 | $0.7366 | $0.7201 | $0.7070 | $0.7122 | $0.7460 | $0.7309 |
| CGA amount | | | $86.39 | $110.49 | $134.67 | $132.92 | $118.23 | $98.47 | $681.17 |
| LDAC | | | $0.0693 | $0.0693 | $0.0693 | $0.0693 | $0.0693 | $0.0693 | 0.0693 |
| LDAC amount | | | $7.56 | $10.40 | $12.97 | $13.04 | $11.51 | $9.15 | $64.63 |
| **Total Bill** | | | **$140.73** | **$176.95** | **$212.08** | **$210.63** | **$189.43** | **$159.61** | **$1,089.44** |

**May 1, 2011 - October 31, 2011**

| May-11 | Jun-11 | Jul-11 | Aug-11 | Sep-11 | Oct-11 | Summer May-Oct | Total Nov-Oct |
|---|---|---|---|---|---|---|---|
| 90 | 55 | 30 | 30 | 42 | 71 | 318 | 1,250 |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| $17.16 | $17.16 | $17.33 | $17.33 | $17.33 | $17.33 | $103.64 | $207.62 |
| $5.43 | $5.43 | $5.48 | $5.48 | $5.48 | $5.48 | $32.78 | $197.24 |
| $15.70 | $7.85 | $2.27 | $2.27 | $4.98 | $11.55 | $44.62 | $119.81 |
| | | | | | | | |
| $38.29 | $30.44 | $25.08 | $25.08 | $27.80 | $34.36 | $181.04 | $524.68 |
| | | | | | | | |
| $0.7326 | $0.7429 | $0.7612 | $0.7884 | $0.7581 | $0.7585 | $0.7515 | $0.7361 |
| $65.93 | $40.86 | $22.84 | $23.65 | $31.84 | $53.85 | $238.98 | $920.14 |
| | | | | | | | |
| $0.0693 | $0.0693 | $0.0693 | $0.0693 | $0.0693 | $0.0693 | $0.0693 | $0.0693 |
| $6.24 | $3.81 | $2.08 | $2.08 | $2.91 | $4.92 | $22.04 | $86.67 |
| | | | | | | | |
| **$110.46** | **$75.11** | **$49.99** | **$50.81** | **$62.55** | **$93.14** | **$442.05** | **$1,531.49** |

**DIFFERENCE:**

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Total Bill** | **($17.94)** | **($16.28)** | **($17.22)** | **($14.85)** | **($13.98)** | **($15.58)** | **($95.85)** | **($19.49)** | **($14.48)** | **($8.78)** | **($8.05)** | **($9.17)** | **($15.52)** | **($75.49)** | **($171.34)** |
| % Change | **-12.75%** | **-9.20%** | **-8.12%** | **-7.05%** | **-7.38%** | **-9.76%** | **-8.80%** | **-17.64%** | **-19.28%** | **-17.55%** | **-15.84%** | **-14.67%** | **-16.67%** | **-17.08%** | **-11.19%** |
| **Base Rate** | ($0.04) | ($0.05) | ($0.06) | ($0.06) | ($0.05) | ($0.05) | ($0.31) | $0.38 | $0.30 | ($0.03) | ($0.03) | ($0.03) | ($0.03) | $0.56 | $0.26 |
| % Change | -0.09% | -0.09% | -0.09% | -0.09% | -0.09% | -0.09% | -0.09% | 0.99% | 0.99% | -0.10% | -0.10% | -0.10% | -0.10% | 0.31% | 0.05% |
| **CGA & LDAC** | ($17.90) | ($16.23) | ($17.16) | ($14.79) | ($13.92) | ($15.53) | ($95.54) | ($19.87) | ($14.78) | ($8.75) | ($8.02) | ($9.15) | ($15.49) | ($76.05) | ($171.60) |
| % Change | -20.72% | -14.69% | -12.75% | -11.13% | -11.78% | -15.77% | -14.03% | -30.13% | -36.18% | -38.31% | -33.91% | -28.72% | -28.76% | -31.83% | -18.65% |

00000120

**ENERGY NORTH NATURAL GAS, INC.**

**Peak 2012 - 2013 Winter Cost of Gas Filing**
**Annual Bill Comparisons, Nov 11 - Apr 12 vs Nov 12 - Apr 13 - Commercial Rate G-41**

**November 1, 2012 - April 30, 2013**
**Commercial Rate (G-41)**

| | | | Nov-12 | Dec-12 | Jan-13 | Feb-13 | Mar-13 | Apr-13 | Winter Nov-Apr |
|---|---|---|---|---|---|---|---|---|---|
| **Typical Usage (Therms)** | | | 193 | 269 | 298 | 262 | 234 | 171 | 1,427 |
| **Winter:** | 07/01/2012 | 07/01/2011 | | | | | | | |
| Cust. Chg | $40.74 | $40.77 | $40.74 | $40.74 | $40.74 | $40.74 | $40.74 | $40.74 | $244.44 |
| Headblock | $0.3251 | $0.3254 | $32.51 | $32.51 | $32.51 | $32.51 | $32.51 | $32.51 | $195.06 |
| Tailblock | $0.2114 | $0.2116 | $19.66 | $35.73 | $41.86 | $34.25 | $28.33 | $15.01 | $174.83 |
| HB Threshold | 100 | 100 | | | | | | | |
| **Summer:** | | | | | | | | | |
| Cust. Chg | $40.74 | $40.77 | | | | | | | |
| Headblock | $0.3251 | $0.3254 | | | | | | | |
| Tailblock | $0.2114 | $0.2116 | | | | | | | |
| HB Threshold | 20 | 20 | | | | | | | |
| Total Base Rate Amount | | | $92.91 | $108.98 | $115.11 | $107.50 | $101.58 | $88.26 | $614.33 |
| CGA Rate - (Seasonal) | | | $0.6736 | $0.6736 | $0.6736 | $0.6736 | $0.6736 | $0.6736 | $0.6736 |
| CGA amount | | | $130.00 | $181.20 | $200.73 | $176.48 | $157.62 | $115.19 | $961.23 |
| LDAC | | | $0.0187 | $0.0187 | $0.0187 | $0.0187 | $0.0187 | $0.0187 | 0.0187 |
| LDAC amount | | | $3.61 | $5.03 | $5.57 | $4.90 | $4.38 | $3.20 | $26.68 |
| **Total Bill** | | | **$226.52** | **$295.21** | **$321.41** | **$288.88** | **$263.58** | **$206.64** | **$1,602.24** |

**May 1, 2012 - October 31, 2012**

| May-12 | Jun-12 | Jul-12 | Aug-12 | Sep-12 | Oct-12 | Summer May-Oct | Total Nov-Oct |
|---|---|---|---|---|---|---|---|
| 117 | 81 | 72 | 72 | 89 | 142 | 573 | 2,000 |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| $40.77 | $40.77 | $40.74 | $40.74 | $40.74 | $40.74 | $244.50 | $488.94 |
| $6.51 | $6.51 | $6.50 | $6.50 | $6.50 | $6.50 | $39.02 | $234.08 |
| $20.53 | $12.91 | $10.99 | $10.99 | $14.59 | $25.79 | $95.80 | $270.62 | |
| | | | | | | | |
| $67.80 | $60.19 | $58.23 | $58.23 | $61.83 | $73.03 | $379.32 | $993.65 |
| | | | | | | | |
| $0.5126 | $0.4749 | $0.4703 | $0.5218 | $0.5411 | $0.5411 | $0.5146 | $0.6280 |
| $59.97 | $38.47 | $33.86 | $37.57 | $48.16 | $76.84 | $294.87 | $1,256.09 |
| | | | | | | | |
| $0.0493 | $0.0493 | $0.0493 | $0.0493 | $0.0493 | $0.0493 | $0.0493 | $0.0275 |
| $5.77 | $4.00 | $3.55 | $3.55 | $4.39 | $7.01 | $28.28 | $54.96 |
| | | | | | | | |
| **$133.55** | **$102.65** | **$95.65** | **$99.36** | **$114.38** | **$156.88** | **$702.46** | **$2,304.70** |

**November 1, 2011 - April 30, 2012**
**Commercial Rate (G-41)**

| | | | Nov-11 | Dec-11 | Jan-12 | Feb-12 | Mar-12 | Apr-12 | Winter Nov-Apr |
|---|---|---|---|---|---|---|---|---|---|
| **Typical Usage (Therms)** | | | 193 | 269 | 298 | 262 | 234 | 171 | 1,427 |
| **Winter:** | 07/01/2011 | 04/01/2011 | | | | | | | |
| Cust. Chg | $40.77 | $40.37 | $40.77 | $40.77 | $40.77 | $40.77 | $40.77 | $40.77 | $244.62 |
| Headblock | $0.3254 | $0.3222 | 32.54 | 32.54 | 32.54 | 32.54 | 32.54 | 32.54 | $195.24 |
| Tailblock | $0.2116 | $0.2095 | $19.68 | $35.76 | $41.90 | $34.28 | $28.35 | $15.02 | $174.99 |
| HB Threshold | 100 | 100 | | | | | | | |
| **Summer:** | | | | | | | | | |
| Cust. Chg | $40.77 | $40.37 | | | | | | | |
| Headblock | $0.3254 | $0.3222 | | | | | | | |
| Tailblock | $0.2116 | $0.2095 | | | | | | | |
| HB Threshold | 20 | 20 | | | | | | | |
| Total Base Rate Amount | | | $92.99 | $109.07 | $115.21 | $107.59 | $101.66 | $88.33 | $614.85 |
| CGA Rate - (Seasonal) | | | $0.7929 | $0.7369 | $0.7204 | $0.7073 | $0.7125 | $0.7463 | $0.7327 |
| CGA amount | | | $153.03 | $198.22 | $214.69 | $185.32 | $166.73 | $127.62 | $1,045.61 |
| LDAC | | | $0.0493 | $0.0493 | $0.0493 | $0.0493 | $0.0493 | $0.0493 | 0.0493 |
| LDAC amount | | | $9.52 | $13.27 | $14.71 | $12.93 | $11.55 | $8.44 | $70.42 |
| **Total Bill** | | | **$255.54** | **$320.57** | **$344.60** | **$305.84** | **$279.94** | **$224.39** | **$1,730.88** |

**May 1, 2011 - October 31, 2011**

| May-11 | Jun-11 | Jul-11 | Aug-11 | Sep-11 | Oct-11 | Summer May-Oct | Total Nov-Oct |
|---|---|---|---|---|---|---|---|
| 117 | 81 | 72 | 72 | 89 | 142 | 573 | 2,000 |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| $40.37 | $40.37 | $40.77 | $40.77 | $40.77 | $40.77 | $243.82 | $488.44 |
| $6.44 | $6.44 | $6.51 | $6.51 | $6.51 | $6.51 | $38.92 | $234.16 |
| $20.32 | $12.78 | $11.00 | $11.00 | $14.60 | $25.82 | $95.52 | $270.52 |
| | | | | | | | |
| $67.14 | $59.59 | $58.28 | $58.28 | $61.88 | $73.09 | $378.26 | $993.12 |
| | | | | | | | |
| $0.7365 | $0.7468 | $0.7651 | $0.7923 | $0.7620 | $0.7624 | $0.7589 | $0.7402 |
| $86.17 | $60.49 | $55.09 | $57.05 | $67.82 | $108.26 | $434.87 | $1,480.48 |
| | | | | | | | |
| $0.0474 | $0.0474 | $0.0474 | $0.0474 | $0.0474 | $0.0474 | $0.0474 | $0.0488 |
| $5.55 | $3.84 | $3.41 | $3.41 | $4.22 | $6.73 | $27.16 | $97.58 |
| | | | | | | | |
| **$158.85** | **$123.92** | **$116.78** | **$118.74** | **$133.92** | **$188.08** | **$840.30** | **$2,571.18** |

**DIFFERENCE:**

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Total Bill** | **($29.02)** | **($25.36)** | **($23.19)** | **($16.96)** | **($16.37)** | **($17.75)** | **($128.64)** |
| % Change | **-11.36%** | **-7.91%** | **-6.73%** | **-5.54%** | **-5.85%** | **-7.91%** | **-7.43%** |
| **Base Rate** | ($0.08) | ($0.09) | ($0.10) | ($0.09) | ($0.09) | ($0.07) | ($0.53) |
| % Change | -0.08% | -0.09% | -0.09% | -0.09% | -0.09% | -0.08% | -0.09% |
| **CGA & LDAC** | ($28.94) | ($25.27) | ($23.09) | ($16.87) | ($16.28) | ($17.67) | ($128.12) |
| % Change | -18.91% | -12.75% | -10.76% | -9.10% | -9.76% | -13.85% | -12.25% |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| **($25.30)** | **($21.27)** | **($21.13)** | **($19.38)** | **($19.54)** | **($31.21)** | **($137.83)** | **($266.48)** |
| **-15.93%** | **-17.17%** | **-18.10%** | **-16.32%** | **-14.59%** | **-16.59%** | **-16.40%** | **-10.36%** |
| $0.67 | $0.59 | ($0.05) | ($0.05) | ($0.05) | ($0.06) | $1.06 | $0.53 |
| 0.99% | 0.99% | -0.08% | -0.08% | -0.08% | -0.08% | 0.28% | 0.05% |
| ($25.97) | ($21.87) | ($21.09) | ($19.34) | ($19.49) | ($31.15) | ($138.89) | ($267.01) |
| -30.14% | -36.15% | -38.28% | -33.90% | -28.73% | -28.77% | -31.94% | -18.04% |

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**ENERGY NORTH NATURAL GAS, INC.**

**Peak 2012 - 2013 Winter Cost of Gas Filing**
**Annual Bill Comparisons, Nov 11 - Apr 12 vs Nov 12 - Apr 13 - Commercial Rate G-42**

**November 1, 2012 - April 30, 2013**
**C&I High Winter Use Medium G-42**

| | | | Nov-12 | Dec-12 | Jan-13 | Feb-13 | Mar-13 | Apr-13 | Winter Nov-Apr |
|---|---|---|---|---|---|---|---|---|---|
| **Typical Usage (Therms)** | | | 1,553 | 2,578 | 3,265 | 4,103 | 3,402 | 2,473 | 17,374 |
| | 07/01/2012 | 07/01/2011 | | | | | | | |
| **Winter:** | | | | | | | | | |
| Cust. Chg | $122.22 | $122.32 | $122.22 | $122.22 | $122.22 | $122.22 | $122.22 | $122.22 | $733.32 |
| Headblock | $0.3038 | $0.3041 | $303.80 | $303.80 | $303.80 | $303.80 | $303.80 | $303.80 | $1,822.80 |
| Tailblock | $0.2007 | $0.2009 | $110.99 | $316.70 | $454.59 | $622.77 | $482.08 | $295.63 | $2,282.76 |
| HB Threshold | 1,000 | 1,000 | | | | | | | |
| **Summer:** | | | | | | | | | |
| Cust. Chg | $122.22 | $122.32 | | | | | | | |
| Headblock | $0.3038 | $0.3041 | | | | | | | |
| Tailblock | $0.2007 | $0.2009 | | | | | | | |
| HB Threshold | 400 | 400 | | | | | | | |
| Total Base Rate Amount | | | $537.01 | $742.72 | $880.61 | $1,048.79 | $908.10 | $721.65 | $4,838.88 |
| CGA Rate - (Seasonal) | | | $0.6736 | $0.6736 | $0.6736 | $0.6736 | $0.6736 | $0.6736 | $0.6736 |
| CGA amount | | | $1,046.10 | $1,736.54 | $2,199.30 | $2,763.78 | $2,291.59 | $1,665.81 | $11,703.13 |
| LDAC | | | $0.0187 | $0.0187 | $0.0187 | $0.0187 | $0.0187 | $0.0187 | 0.0187 |
| LDAC amount | | | $29.04 | $48.21 | $61.06 | $76.73 | $63.62 | $46.25 | $324.89 |
| **Total Bill** | | | **$1,612.15** | **$2,527.47** | **$3,140.97** | **$3,889.30** | **$3,263.31** | **$2,433.71** | **$16,866.90** |

**May 1, 2012 - October 31, 2012**

| May-12 | Jun-12 | Jul-12 | Aug-12 | Sep-12 | Oct-12 | Summer May-Oct | Total Nov-Oct |
|---|---|---|---|---|---|---|---|
| 1,258 | 701 | 414 | 213 | 364 | 699 | 3,649 | 21,023 |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
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| | | | | | | | |
| | | | | | | | |
| $122.32 | $122.32 | $122.22 | $122.22 | $122.22 | $122.22 | $733.52 | $1,466.84 |
| $121.64 | $121.64 | $121.52 | $64.71 | $110.58 | $121.52 | $661.61 | $2,484.41 |
| $172.37 | $60.47 | $2.81 | $0.00 | $0.00 | $60.01 | $295.66 | $2,578.42 |
| | | | | | | | |
| $416.33 | $304.43 | $246.55 | $186.93 | $232.80 | $303.75 | $1,690.79 | $6,529.68 |
| | | | | | | | |
| $0.5126 | $0.4749 | $0.4703 | $0.5218 | $0.5411 | $0.5411 | $0.5094 | $0.6451 |
| $644.85 | $332.90 | $194.70 | $111.14 | $196.96 | $378.23 | $1,858.79 | $13,561.92 |
| | | | | | | | |
| $0.0493 | $0.0493 | $0.0493 | $0.0493 | $0.0493 | $0.0493 | $0.0493 | $0.0240 |
| $62.08 | $34.59 | $20.43 | $10.51 | $17.96 | $34.49 | $180.07 | $504.96 |
| | | | | | | | |
| **$1,123.26** | **$671.93** | **$461.68** | **$308.58** | **$447.73** | **$716.47** | **$3,729.65** | **$20,596.56** |

**November 1, 2011 - April 30, 2012**
**C&I High Winter Use Medium G-42**

| | | | Nov-11 | Dec-11 | Jan-12 | Feb-12 | Mar-12 | Apr-12 | Winter Nov-Apr |
|---|---|---|---|---|---|---|---|---|---|
| **Typical Usage (Therms)** | | | 1,553 | 2,578 | 3,265 | 4,103 | 3,402 | 2,473 | 17,374 |
| | 07/01/2011 | 04/01/2011 | | | | | | | |
| **Winter:** | | | | | | | | | |
| Cust. Chg | $122.32 | $121.11 | $122.32 | $122.32 | $122.32 | $122.32 | $122.32 | $122.32 | $733.92 |
| Headblock | $0.3041 | $0.3011 | 304.10 | 304.10 | 304.10 | 304.10 | 304.10 | 304.10 | $1,824.60 |
| Tailblock | $0.2009 | $0.1989 | $111.10 | $317.02 | $455.04 | $623.39 | $482.56 | $295.93 | $2,285.04 |
| HB Threshold | 1,000 | 1,000 | | | | | | | |
| **Summer:** | | | | | | | | | |
| Cust. Chg | $122.32 | $121.11 | | | | | | | |
| Headblock | $0.3041 | $0.3011 | | | | | | | |
| Tailblock | $0.2009 | $0.1989 | | | | | | | |
| HB Threshold | 400 | 400 | | | | | | | |
| Total Base Rate Amount | | | $537.52 | $743.44 | $881.46 | $1,049.81 | $908.98 | $722.35 | $4,843.56 |
| CGA Rate - (Seasonal) | | | $0.7929 | $0.7369 | $0.7204 | $0.7073 | $0.7125 | $0.7463 | $0.7284 |
| CGA amount | | | $1,231.37 | $1,899.68 | $2,352.25 | $2,902.16 | $2,424.01 | $1,845.60 | $12,655.07 |
| LDAC | | | $0.0493 | $0.0493 | $0.0493 | $0.0493 | $0.0493 | $0.0493 | 0.0493 |
| LDAC amount | | | $76.64 | $127.22 | $161.12 | $202.47 | $167.88 | $122.03 | $857.35 |
| **Total Bill** | | | **$1,845.53** | **$2,770.33** | **$3,394.82** | **$4,154.44** | **$3,500.87** | **$2,689.98** | **$18,355.98** |

**May 1, 2011 - October 31, 2011**

| May-11 | Jun-11 | Jul-11 | Aug-11 | Sep-11 | Oct-11 | Summer May-Oct | Total Nov-Oct |
|---|---|---|---|---|---|---|---|
| 1,258 | 701 | 414 | 213 | 364 | 699 | 3,649 | 21,023 |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| $121.11 | $121.11 | $122.32 | $122.32 | $122.32 | $122.32 | $731.50 | $1,465.42 |
| $120.44 | $120.44 | $121.64 | $64.77 | $110.69 | $121.64 | $659.63 | $2,484.23 |
| $170.66 | $59.87 | $2.81 | $0.00 | $0.00 | $60.07 | $293.41 | $2,578.44 |
| | | | | | | | |
| $412.21 | $301.42 | $246.77 | $187.09 | $233.01 | $304.03 | $1,684.53 | $6,528.09 |
| | | | | | | | |
| $0.7365 | $0.7468 | $0.7651 | $0.7923 | $0.7620 | $0.7624 | $0.7525 | $0.7326 |
| $926.52 | $523.51 | $316.75 | $168.76 | $277.37 | $532.92 | $2,745.82 | $15,400.89 |
| | | | | | | | |
| $0.0474 | $0.0474 | $0.0474 | $0.0474 | $0.0474 | $0.0474 | $0.0474 | $0.0490 |
| $59.63 | $33.23 | $19.62 | $10.10 | $17.25 | $33.13 | $172.96 | $1,030.31 |
| | | | | | | | |
| **$1,398.35** | **$858.15** | **$583.15** | **$365.95** | **$527.63** | **$870.08** | **$4,603.32** | **$22,959.29** |

**DIFFERENCE:**

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Total Bill** | **($233.38)** | **($242.86)** | **($253.86)** | **($265.14)** | **($237.57)** | **($256.27)** | **($1,489.08)** | |
| % Change | **-12.65%** | **-8.77%** | **-7.48%** | **-6.38%** | **-6.79%** | **-9.53%** | **-8.11%** | |
| **Base Rate** | ($0.51) | ($0.72) | ($0.85) | ($1.02) | ($0.88) | ($0.69) | ($4.67) | |
| % Change | -0.09% | -0.10% | -0.10% | -0.10% | -0.10% | -0.10% | -0.10% | |
| **CGA & LDAC** | ($232.87) | ($242.15) | ($253.01) | ($264.12) | ($236.69) | ($255.58) | ($1,484.40) | |
| % Change | -18.91% | -12.75% | -10.76% | -9.10% | -9.76% | -13.85% | -11.73% | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **($275.09)** | **($186.23)** | **($121.46)** | **($57.37)** | **($79.91)** | **($153.61)** | **($873.66)** | **($2,362.74)** | |
| **-19.67%** | **-21.70%** | **-20.83%** | **-15.68%** | **-15.14%** | **-17.65%** | **-18.98%** | **-10.29%** | |
| $4.13 | $3.01 | ($0.22) | ($0.16) | ($0.21) | ($0.28) | $6.26 | $1.59 | |
| 1.00% | 1.00% | -0.09% | -0.09% | -0.09% | -0.09% | 0.37% | 0.02% | |
| ($279.22) | ($189.24) | ($121.24) | ($57.20) | ($79.70) | ($153.33) | ($879.92) | ($2,364.33) | |
| -30.14% | -36.15% | -38.28% | -33.90% | -28.73% | -28.77% | -32.05% | -15.35% | |

00000122

**ENERGY NORTH NATURAL GAS, INC.**

**Peak 2012 - 2013 Winter Cost of Gas Filing**
**Annual Bill Comparisons, Nov 11 - Apr 12 vs Nov 12 - Apr 13 - Commercial Rate G-52**

**November 1, 2012 - April 30, 2013**
**Commercial Rate (G-52)**

| | | | Nov-12 | Dec-12 | Jan-13 | Feb-13 | Mar-13 | Apr-13 | Winter Nov-Apr |
|---|---|---|---|---|---|---|---|---|---|
| **Typical Usage (Therms)** | | | 1,722 | 2,086 | 2,330 | 2,333 | 2,291 | 1,872 | 12,634 |
| **Winter:** | 07/01/2012 | 07/01/2011 | | | | | | | |
| Cust. Chg | $122.22 | $122.32 | $122.22 | $122.22 | $122.22 | $122.22 | $122.22 | $122.22 | $733.32 |
| Headblock | $0.1683 | $0.1684 | $168.30 | $168.30 | $168.30 | $168.30 | $168.30 | $168.30 | $1,009.80 |
| Tailblock | $0.1142 | $0.1143 | $82.45 | $124.02 | $151.89 | $152.23 | $147.43 | $99.58 | $757.60 |
| HB Threshold | 1,000 | 1,000 | | | | | | | |
| **Summer:** | | | | | | | | | |
| Cust. Chg | $122.22 | $122.32 | | | | | | | |
| Headblock | $0.1236 | $0.1237 | | | | | | | |
| Tailblock | $0.0712 | $0.0713 | | | | | | | |
| HB Threshold | 1,000 | 1,000 | | | | | | | |
| Total Base Rate Amount | | | $372.97 | $414.54 | $442.41 | $442.75 | $437.95 | $390.10 | $2,500.72 |
| CGA Rate - (Seasonal) | | | $0.6671 | $0.6671 | $0.6671 | $0.6671 | $0.6671 | $0.6671 | $0.6671 |
| CGA amount | | | $1,148.75 | $1,391.57 | $1,554.34 | $1,556.34 | $1,528.33 | $1,248.81 | $8,428.14 |
| LDAC | | | $0.0187 | $0.0187 | $0.0187 | $0.0187 | $0.0187 | $0.0187 | 0.0187 |
| LDAC amount | | | $32.20 | $39.01 | $43.57 | $43.63 | $42.84 | $35.01 | $236.26 |
| **Total Bill** | | | **$1,553.92** | **$1,845.12** | **$2,040.32** | **$2,042.72** | **$2,009.12** | **$1,673.92** | **$11,165.12** |

**May 1, 2012 - October 31, 2012**

| May-12 | Jun-12 | Jul-12 | Aug-12 | Sep-12 | Oct-12 | Summer May-Oct | Total Nov-Oct |
|---|---|---|---|---|---|---|---|
| 1,510 | 1,374 | 1,247 | 1,190 | 1,210 | 1,324 | 7,855 | 20,489 |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| $122.32 | $122.32 | $122.22 | $122.22 | $122.22 | $122.22 | $733.52 | $1,466.84 |
| $123.70 | $123.70 | $123.60 | $123.60 | $123.60 | $123.60 | $741.80 | $1,751.60 |
| $36.36 | $26.67 | $17.59 | $13.53 | $14.95 | $23.07 | $132.16 | $889.77 |
| | | | | | | | |
| $282.38 | $272.69 | $263.41 | $259.35 | $260.77 | $268.89 | $1,607.48 | $4,108.21 |
| | | | | | | | |
| $0.5103 | $0.4726 | $0.4680 | $0.5195 | $0.5388 | $0.5388 | $0.5076 | $0.6059 |
| $770.55 | $649.35 | $583.60 | $618.21 | $651.95 | $713.37 | $3,987.03 | $12,415.17 |
| | | | | | | | |
| $0.0493 | $0.0493 | $0.0493 | $0.0493 | $0.0493 | $0.0493 | $0.0493 | $0.0304 |
| $74.51 | $67.80 | $61.54 | $58.72 | $59.71 | $65.33 | $387.62 | $623.87 |
| | | | | | | | |
| **$1,127.45** | **$989.84** | **$908.54** | **$936.28** | **$972.43** | **$1,047.59** | **$5,982.13** | **$17,147.25** |

**November 1, 2011 - April 30, 2012**
**Commercial Rate (G-52)**

| | | | Nov-11 | Dec-11 | Jan-12 | Feb-12 | Mar-12 | Apr-12 | Winter Nov-Apr |
|---|---|---|---|---|---|---|---|---|---|
| **Typical Usage (Therms)** | | | 1,722 | 2,086 | 2,330 | 2,333 | 2,291 | 1,872 | 12,634 |
| **Winter:** | 07/01/2011 | 04/01/2011 | | | | | | | |
| Cust. Chg | $122.32 | $121.11 | $122.32 | $122.32 | $122.32 | $122.32 | $122.32 | $122.32 | $733.92 |
| Headblock | $0.1684 | $0.1667 | 168.40 | 168.40 | 168.40 | 168.40 | 168.40 | 168.40 | $1,010.40 |
| Tailblock | $0.1143 | $0.1131 | $82.52 | $124.13 | $152.02 | $152.36 | $147.56 | $99.67 | $758.27 |
| HB Threshold | 1,000 | 1,000 | | | | | | | |
| **Summer:** | | | | | | | | | |
| Cust. Chg | $122.32 | $121.11 | | | | | | | |
| Headblock | $0.1237 | $0.1225 | | | | | | | |
| Tailblock | $0.0713 | $0.0705 | | | | | | | |
| HB Threshold | 1,000 | 1,000 | | | | | | | |
| Total Base Rate Amount | | | $373.24 | $414.85 | $442.74 | $443.08 | $438.28 | $390.39 | $2,502.59 |
| CGA Rate - (Seasonal) | | | $0.7911 | $0.7351 | $0.7186 | $0.7055 | $0.7107 | $0.7445 | $0.7312 |
| CGA amount | | | $1,362.27 | $1,533.38 | $1,674.44 | $1,645.99 | $1,628.27 | $1,393.70 | $9,238.06 |
| LDAC | | | $0.0493 | $0.0493 | $0.0493 | $0.0493 | $0.0493 | $0.0493 | 0.0493 |
| LDAC amount | | | $84.97 | $102.94 | $114.98 | $115.13 | $113.05 | $92.38 | $623.45 |
| **Total Bill** | | | **$1,820.49** | **$2,051.17** | **$2,232.16** | **$2,204.20** | **$2,179.61** | **$1,876.47** | **$12,364.09** |

**May 1, 2011 - October 31, 2011**

| May-11 | Jun-11 | Jul-11 | Aug-11 | Sep-11 | Oct-11 | Summer May-Oct | Total Nov-Oct |
|---|---|---|---|---|---|---|---|
| 1,510 | 1,374 | 1,247 | 1,190 | 1,210 | 1,324 | 7,855 | 20,489 |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| $121.11 | $121.11 | $122.32 | $122.32 | $122.32 | $122.32 | $731.50 | $1,465.42 |
| $122.50 | $122.50 | $123.70 | $123.70 | $123.70 | $123.70 | $739.80 | $1,750.20 |
| $35.96 | $26.37 | $17.61 | $13.55 | $14.97 | $23.10 | $131.55 | $889.82 |
| | | | | | | | |
| $279.57 | $269.98 | $263.63 | $259.57 | $260.99 | $269.12 | $1,602.85 | $4,105.44 |
| | | | | | | | |
| $0.7256 | $0.7359 | $0.7542 | $0.7814 | $0.7511 | $0.7515 | $0.7487 | $0.7379 |
| $1,095.66 | $1,011.13 | $940.49 | $929.87 | $908.83 | $994.99 | $5,880.95 | $15,119.01 |
| | | | | | | | |
| $0.0474 | $0.0474 | $0.0474 | $0.0474 | $0.0474 | $0.0474 | $0.0474 | $0.0486 |
| $71.57 | $65.13 | $59.11 | $56.41 | $57.35 | $62.76 | $372.33 | $995.77 |
| | | | | | | | |
| **$1,446.80** | **$1,346.23** | **$1,263.23** | **$1,245.84** | **$1,227.18** | **$1,326.86** | **$7,856.13** | **$20,220.23** |

**DIFFERENCE:**

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Total Bill** | **($266.57)** | **($206.05)** | **($191.84)** | **($161.48)** | **($170.49)** | **($202.55)** | **($1,198.97)** | **($319.35)** | **($356.39)** | **($354.69)** | **($309.56)** | **($254.75)** | **($279.27)** | **($1,874.01)** | **($3,072.98)** |
| % Change | **-14.64%** | **-10.05%** | **-8.59%** | **-7.33%** | **-7.82%** | **-10.79%** | **-9.70%** | **-22.07%** | **-26.47%** | **-28.08%** | **-24.85%** | **-20.76%** | **-21.05%** | **-23.85%** | **-15.20%** |
| **Base Rate** | ($0.27) | ($0.31) | ($0.33) | ($0.33) | ($0.33) | ($0.29) | ($1.86) | $2.82 | $2.71 | ($0.22) | ($0.22) | ($0.22) | ($0.23) | $4.63 | $2.77 |
| % Change | -0.07% | -0.07% | -0.08% | -0.08% | -0.08% | -0.07% | -0.07% | 1.01% | 1.00% | -0.09% | -0.08% | -0.08% | -0.09% | 0.29% | 0.07% |
| **CGA & LDAC** | ($266.30) | ($205.74) | ($191.50) | ($161.15) | ($170.16) | ($202.26) | ($1,197.11) | ($322.16) | ($359.10) | ($354.46) | ($309.34) | ($254.53) | ($279.04) | ($1,878.64) | ($3,075.75) |
| % Change | -19.55% | -13.42% | -11.44% | -9.79% | -10.45% | -14.51% | -12.96% | -29.40% | -35.51% | -37.69% | -33.27% | -28.01% | -28.04% | -31.94% | -20.34% |

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**ENERGY NORTH NATURAL GAS, INC.**

**Peak 2012 - 2013 Winter Cost of Gas Filing**

**Residential Heating**

| | Winter 2011-12 | Winter 2012-13 |
|---|---|---|
| Customer Charge | $17.33 | $17.31 |
| First 100 Therms | $0.2741 | $0.2739 |
| Excess 100 Therms | $0.2265 | $0.2263 |
| LDAC | $0.0693 | $0.0258 |
| CGA | $0.7309 | $0.6719 |
| Total Adjust | $0.8002 | $0.6977 |

| | Winter 2011-12 CGA @ | | Winter 2012-13 CGA @ | Total | | Base Rate | | CGA | | LDAC | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | $0.8002 | $0.6977 | $ Impact | % Impact | $ Impact | % Impact | $ Impact | % Impact | $ Impact | % Impact |
| | | | | ($0.10) | -13% | | | | | | |
| Cooking alone | 5 | $22.70 | $22.17 | ($0.53) | -2% | -$0.02 | 0% | -$0.29 | -1% | -$0.22 | -1% |
| | 10 | $28.07 | $27.03 | ($1.05) | -4% | -$0.02 | 0% | -$0.59 | -2% | -$0.44 | -2% |
| | 20 | $38.82 | $36.74 | ($2.07) | -5% | -$0.02 | 0% | -$1.18 | -3% | -$0.87 | -2% |
| Water Heating alone | 30 | $49.56 | $46.46 | ($3.10) | -6% | -$0.03 | 0% | -$1.77 | -4% | -$1.31 | -3% |
| | 45 | $65.67 | $61.03 | ($4.64) | -7% | -$0.03 | 0% | -$2.65 | -4% | -$1.96 | -3% |
| | 50 | $71.05 | $65.89 | ($5.16) | -7% | -$0.03 | 0% | -$2.95 | -4% | -$2.18 | -3% |
| Heating Alone | 80 | $97.90 | $90.18 | ($7.72) | -8% | -$0.04 | 0% | -$4.42 | -5% | -$3.27 | -3% |
| | 125 | $158.64 | $144.96 | ($13.68) | -9% | -$0.05 | 0% | -$7.84 | -5% | -$5.79 | -4% |
| | 150 | $176.10 | $160.67 | ($15.43) | -9% | -$0.05 | 0% | -$8.85 | -6% | -$6.53 | -4% |
| | 200 | $227.43 | $206.87 | ($20.56) | -9% | -$0.06 | 0% | -$11.79 | -6% | -$8.71 | -4% |

**ENERGY NORTH NATURAL GAS, INC.**

**Peak 2012 - 2013 Winter Cost of Gas Filing**
**Variance Analysis of the Components of the Winter 2011-12 Actual Results vs Proposed Winter 2012-13 Cost of Gas Rate**

| | WINTER SALES ACTUAL RESULTS (6 months actual) | | | WINTER 2011-12 (6 months Proposed) | | |
|---|---|---|---|---|---|---|
| Therm Sales | 65,771,915 | | | 77,755,617 | | |
| | THERM SENDOUT | COSTS | EFFECT ON COST OF GAS | THERM SENDOUT | COSTS | EFFECT ON COST OF GAS |
| Demand Charges | | $ 9,753,327 | $ 0.1483 | | $ 10,538,954 | $ 0.1355 |
| Purchased Gas | 61,918,285 | 25,445,436 | 0.3869 | 58,646,280 | 26,630,667 | 0.3425 |
| Storage Gas | 5,321,960 | 2,554,402 | 0.0388 | 20,522,810 | 9,121,704 | 0.1173 |
| Produced Gas | 869,735 | 317,581 | 0.0048 | 819,280 | 291,366 | 0.0037 |
| Hedging (Gain)/Loss | | 6,802,122 | 0.1034 | | 1,941,641 | 0.0250 |
| Total Volumes and Cost | 68,109,980 | $ 44,872,868 | $ 0.6822 | 79,988,370 | $ 48,524,333 | $ 0.6241 |
| Direct Costs | | | | | | |
| Prior Period Balance | | $ 3,735,297 | $ 0.0568 | | 1,606,569 | $ 0.0207 |
| Interest | | 138,331 | 0.0021 | | 73,865 | 0.0009 |
| Prior Period Adjustment | | (43,023) | (0.0007) | | - | - |
| Broker Revenues | | (1,015,743) | (0.0154) | | (396,197) | (0.0051) |
| Refunds from Suppliers | | - | - | | - | - |
| Fuel Financing | | 144,515 | 0.0022 | | 109,724 | 0.0014 |
| Transportation CGA Revenues | | - | - | | (8,224) | (0.0001) |
| 280 Day Margin | | - | - | | - | - |
| Interruptible Sales Margin | | - | - | | - | - |
| Capacity Release and Off System Sales Margins | | (770,313) | (0.0117) | | (1,130,619) | (0.0145) |
| Hedging Costs | | - | - | | - | - |
| FPO Admin Costs | | - | - | | 40,691 | 0.0005 |
| Indirect Costs | | | | | | |
| Misc Overhead | | 10,337 | 0.0002 | | 10,735 | 0.0001 |
| Occupant Disallowance/Credits | | - | | | | |
| Production & Storage | | 1,980,428 | 0.0301 | | 1,980,428 | 0.0255 |
| Other Indirect Gas Costs | | 1,422,499 | 0.0216 | | 1,429,276 | 0.0184 |
| Total Adjusted Cost | | $ 50,475,195 | **$ 0.7674** | | $ 52,240,580 | **$ 0.6719** |

**ENERGY NORTH NATURAL GAS, INC.**

## Peak 2012 - 2013 Winter Cost of Gas Filing
## Capacity Assignment Calculations 2012-2013
## Derivation of Class Assignments and Weightings

Basic assumptions:

1 Residential class pays average seasonal gas cost rate (using MBA method to allocate costs to seasons)
2 Residual gas costs are allocated to C&I HLF and LLF classes based on MBA method
3 The MBA method allocates capacity costs based on design day demands in two pieces:
  a The base use portion of the class design day demand based on base use
  b The remaining portion of design day demand based on remaining design day demand
4 Base demand is composed solely of pipeline supplies
5 Remaining demand consists of a portion of pipeline and all storage and peaking supplies

| | | | | Column A | Column B | Column C | Column D | Column E | Column F |
|---|---|---|---|---|---|---|---|---|---|
| | | | | Design Day Demand. Dktherm | Adjusted Design Day Demand, Dt | Percent of Total | | Avg Daily Base Use Load, Dt | Remaining Design Day Demand |
| 1 | RATE R-1-Resi Non-Htg | | | 710 | 693 | 0.5% | | 132 | 561 |
| 2 | RATE R-3-Resi Htg | | | 66,635 | 64,807 | 47.0% | | 3,712 | 61,095 |
| 3 | RATE G-41 (T) | | | 24,355 | 23,672 | 17.2% | | 841 | 22,831 |
| 4 | RATE G-51 (S) | | | 2,663 | 2,604 | 1.9% | | 636 | 1,968 |
| 5 | RATE G-42 (V) | | | 35,322 | 34,345 | 24.9% | | 1,721 | 32,624 |
| 6 | RATE G-52 | | | 4,184 | 4,099 | 3.0% | | 1,263 | 2,836 |
| 7 | RATE G-43 | | | 4,276 | 4,163 | 3.0% | | 401 | 3,762 |
| 8 | RATE G-53 | | | 1,804 | 1,759 | 1.3% | | 257 | 1,502 |
| 9 | RATE G-54 | | | 1,912 | 1,859 | 1.3% | | 98 | 1,761 |
| 10 | | | | | | | | | |
| 11 | Total | | | 141,860 | 138,001 | 100.0% | | 9,060 | 128,941 |
| 12 | | | | | | | | | - |
| 13 | Residential Total | | | 67,345 | 65,500 | **47.463%** | | 3,844 | 61,656 |
| 14 | LLF Total | | | 63,953 | 62,180 | **45.058%** | | 2,962 | 59,218 |
| 15 | HLF Total | | | 10,562 | 10,321 | **7.479%** | | 2,254 | 8,067 |
| 16 | Total | | | 141,860 | 138,001 | 100.0% | | 9,060 | 128,941 |
| 17 | | | | | | | | | |
| 18 | C&I Breakdown | | | | | | | | |
| 19 | LLF Total | | | | | | | 2,962 | 59,218 |
| 20 | HLF Total | | | | | | | 2,254 | 8,067 |
| 21 | Total | | | | | | | 5,216 | 67,285 |
| 22 | | | | | | | | | |
| 23 | C&I Breakdown Percentage | | | | | | | | |
| 24 | LLF Total | | | | | | | 56.791% | 88.010% |
| 25 | HLF Total | | | | | | | 43.209% | 11.990% |
| 26 | Total | | | | | | | **100.0%** | **100.0%** |
| 27 | | | | | | | | | |
| 28 | | | | Capacity Cost | MDQ, Dt | $/Dt-Mo. | | | |
| 29 | Pipeline | | | $5,792,874 | 53,718 | $8.9866 | | | |
| 30 | Storage | | | $5,573,306 | 28,115 | $16.5194 | | | |
| 31 | | | | | | | | | |
| 32 | Peaking | | | $6,945,969 | | | | | |
| 33 | Peaking Additional Costs (Concord Lateral Peaking x Differential) | | | $2,462,292 | | | | | |
| 34 | Subtotal Peaking Costs | | | $9,408,262 | 56,167 | $13.9588 | | | |
| 35 | Total | | | $20,774,441 | 138,000 | $12.5450 | | | |
| 36 | | | | | | | | | |
| 37 | | | | Capacity Cost | MDQ, Dt | $/Dt-Mo. | | | |
| 38 | Pipeline - Baseload | | | 977,044 | 9,060 | $8.9866 | | | |
| 39 | Pipeline - Remaining | | | 4,815,830 | 44,658 | $8.9865 | | | |
| 40 | Storage | | | 5,573,306 | 28,115 | $16.5194 | | | |
| 41 | Peaking | | | 9,408,262 | 56,167 | $13.9588 | | | |
| 42 | Total | | | 20,774,441 | 138,000 | $12.5450 | | | |
| 43 | | | | | | | | | |
| 44 | | | | | | | | | |
| 45 | Residential Allocation | | | Capacity Cost | MDQ, Dt | $/Dt-Mo. | | | |
| 46 | Pipeline - Base | Line 38 * Line 13 Col C | **47.463%** | 463,734 | 4,300 | $8.9866 | | | |
| 47 | Pipeline - Remaining | Line 39 * Line 13 Col C | **47.463%** | 2,285,728 | 21,196 | $8.9865 | | | |
| 48 | Storage | Line 40 * Line 13 Col C | **47.463%** | 2,645,262 | 13,344 | $16.5194 | | | |
| 49 | Peaking | Line 41 * Line 13 Col C | **47.463%** | 4,465,532 | 26,659 | $13.9588 | | | |
| 50 | Total | | **47.464%** | 9,860,280 | 65,499 | $12.5450 | | | |

**ENERGY NORTH NATURAL GAS, INC.**

## Peak 2012 - 2013 Winter Cost of Gas Filing
## Capacity Assignment Calculations 2012-2013
## Derivation of Class Assignments and Weightings

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 51 | | | | | | | |
| 52 | | | | | | | **Ratios for COG** |
| 53 | C&I Allocation | | | Capacity Cost | MDQ, Dt | $/Dt-Mo. | |
| 54 | Pipeline - Base | Line 38 - Line 46 | | 513,310 | 4,760 | $8.9866 | |
| 55 | Pipeline - Remaining | Line 39 - Line 47 | | 2,530,103 | 23,462 | $8.9866 | |
| 56 | Storage | Line 40 - Line 48 | | 2,928,043 | 14,771 | $16.5193 | |
| 57 | Peaking | Line 41 - Line 49 | | 4,942,730 | 29,508 | $13.9587 | |
| 58 | Total | | **52.537%** | 10,914,185 | 72,501 | $12.5449 | **1.0000** |
| 59 | | | | | | | |
| 60 | | | | | | | |
| 61 | LLF - C&I Allocation | | | Capacity Cost | MDQ, Dt | $/Dt-Mo. | |
| 62 | Pipeline - Base | Line 54 * Line 24 Col E | | 291,516 | 2,703 | $8.9874 | |
| 63 | Pipeline - Remaining | Line 55 * Line 24 Col F | | 2,226,755 | 20,649 | $8.9865 | |
| 64 | Storage | Line 56 * Line 24 Col F | | 2,576,985 | 13,000 | $16.5191 | |
| 65 | Peaking | Line 57 * Line 24 Col F | | 4,350,120 | 25,970 | $13.9588 | |
| 66 | Total | | **45.4663%** | 9,445,376 | 62,322 | $12.6298 | **1.0068** |
| 67 | | | 56.791% | 87% | | | (Line 66 / Line 58) |
| 68 | | | | | | | |
| 69 | HLF - C&I Allocation | | | Capacity Cost | MDQ, Dt | $/Dt-Mo. | |
| 70 | Pipeline - Base | Line 54 - Line 62 | | 221,794 | 2,057 | $8.9853 | |
| 71 | Pipeline - Remaining | Line 55 - Line 63 | | 303,348 | 2,813 | $8.9865 | |
| 72 | Storage | Line 56 - Line 64 | | 351,058 | 1,771 | $16.5188 | |
| 73 | Peaking | Line 57 - Line 65 | | 592,610 | 3,538 | $13.9582 | |
| 74 | Total | | **7.0703%** | 1,468,810 | 10,179 | $12.0248 | **0.9585** |
| 75 | | | | | | | (Line 74 / Line 58) |
| 76 | | | | | | | |

| | | | | |
|---|---|---|---|---|
| 77 | Unit Cost | Residential | LLF C&I | HLF C&I |
| 78 | | | | |
| 79 | Pipeline | $ 8.9866 | $ 8.9866 | $ 8.9866 |
| 80 | Storage | $ 16.5194 | $ 16.5194 | $ 16.5194 |
| 81 | Peaking | $ - | $ - | $ - |
| 82 | Total | $ 12.5450 | $ 12.6298 | $ 12.0248 |
| 83 | | | | |
| 84 | | | | |
| 85 | Load Makeup | Residential | **LLF C&I** | **HLF C&I** |
| 86 | | | | |
| 87 | Pipeline | 38.93% | **37.47%** | **47.84%** |
| 88 | Storage | 20.37% | **20.86%** | **17.40%** |
| 89 | Peaking | 40.70% | **41.67%** | **34.76%** |
| 90 | Total | 100.00% | **100.00%** | **100.00%** |
| 91 | | | | |
| 92 | | | | |

| | | | | | |
|---|---|---|---|---|---|
| 93 | Supply Makeup | Residential | LLF C&I | HLF C&I | Total |
| 94 | | | | | |
| 95 | Pipeline | 47.46% | 43.47% | 9.07% | 100.00% |
| 96 | Storage | 47.46% | 46.24% | 6.30% | 100.00% |
| 97 | Peaking | 47.46% | 46.24% | 6.30% | 100.00% |

**ENERGY NORTH NATURAL GAS, INC.**

**Peak 2012 - 2013 Winter Cost of Gas Filing**
**Correction Factor Calculation**

Data Source: Schedule 10B

| | Nov | Dec | Jan | Feb | Mar | Apr | Total Sales |
|---|---|---|---|---|---|---|---|
| G-41 | 793,973 | 1,753,113 | 2,931,550 | 3,164,977 | 2,685,436 | 1,726,896 | 13,055,944 |
| G-42 | 977,234 | 1,816,915 | 2,718,933 | 2,940,752 | 2,590,088 | 1,730,163 | 12,774,086 |
| G-43 | 111,415 | 167,717 | 229,066 | 238,181 | 206,197 | 139,916 | 1,092,492 |
| High Winter Use | 1,882,621 | 3,737,744 | 5,879,550 | 6,343,911 | 5,481,721 | 3,596,975 | 26,922,523 |
| G-51 | 187,448 | 274,514 | 359,907 | 385,766 | 332,045 | 241,900 | 1,781,580 |
| G-52 | 223,378 | 294,954 | 368,393 | 347,643 | 326,431 | 252,589 | 1,813,388 |
| G-53 | 30,712 | 35,448 | 45,707 | 46,192 | 43,680 | 34,154 | 235,893 |
| G-54 | 641 | 739 | 929 | 919 | 3,772 | 4,964 | 11,964 |
| Low Winter Use | 442,179 | 605,654 | 774,936 | 780,520 | 705,929 | 533,607 | 3,842,824 |
| Gross Total | 2,324,800 | 4,343,398 | 6,654,486 | 7,124,430 | 6,187,650 | 4,130,582 | 30,765,347 |

| | | |
|---|---|---|
| Total Sales | 30,765,347 | |
| Low Winter Use | 3,842,824 | |
| Winter Ratio for Low Winter Use = | **0.95850** | Schedule 10A p 2, ln 74 |
| High Winter Use | 26,922,523 | |
| Winter Ratio for High Winter Use = | **1.00680** | Schedule 10A p 2, ln 66 |

Correction Factor = Total Sales/((Low Winter Use x Winter Ratio for Low Winter Use)+(High Winter Use x Winter Ratio for High Winter Use))

Correction Factor = **99.9234%**

**Allocation Calculation for Miscellaneous Overhead**

| | | | |
|---|---|---|---|
| Projected Winter Sales Volume | (11/1/12 - 4/30/13) | 77,826,455 | Sch.10B |
| Projected Annual Sales Volume | (11/1/12 - 10/31/13) | 95,484,050 | Sch.10B |
| Percentage of Winter to Annual Sales | | 81.51% | |

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**ENERGY NORTH NATURAL GAS, INC.**

**Peak 2012 - 2013 Winter Cost of Gas Filing**
**2012 - 2013 Winter Cost of Gas Filing**

**Dry Therms**

| **Firm Sales** | **Nov-12** | **Dec-12** | **Jan-13** | **Feb-13** | **Mar-13** | **Apr-13** | **Subtotal PK 12-13** | **May-13** | **Jun-13** | **Jul-13** | **Aug-13** | **Sep-13** | **Oct-13** | **Subtotal OP 13** | **Total** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| R-1 | 64,166 | 88,417 | 111,208 | 113,714 | 102,801 | 83,421 | 563,726 | 67,153 | 54,234 | 47,099 | 38,571 | 41,431 | 48,833 | 297,320 | 861,046 |
| R-3 | 3,469,410 | 6,479,481 | 9,405,373 | 10,057,648 | 8,632,848 | 5,809,694 | 43,854,454 | 3,075,847 | 1,809,921 | 1,139,367 | 964,835 | 1,045,881 | 1,566,338 | 9,602,189 | 53,456,643 |
| R-4 | 244,831 | 378,321 | 542,475 | 583,409 | 533,298 | 360,593 | 2,642,927 | 206,634 | 120,743 | 66,195 | 53,269 | 55,801 | 78,362 | 581,004 | 3,223,932 |
| Total Residential. | 3,778,407 | 6,946,220 | 10,059,056 | 10,754,770 | 9,268,947 | 6,253,708 | 47,061,107 | 3,349,634 | 1,984,898 | 1,252,661 | 1,056,675 | 1,143,113 | 1,693,533 | 10,480,513 | 57,541,620 |
| G-41 | 793,973 | 1,753,113 | 2,931,550 | 3,164,977 | 2,685,436 | 1,726,896 | 13,055,944 | 763,239 | 448,943 | 206,222 | 188,227 | 195,440 | 281,384 | 2,083,454 | 15,139,399 |
| G-42 | 977,234 | 1,816,915 | 2,718,933 | 2,940,752 | 2,590,088 | 1,730,163 | 12,774,086 | 933,331 | 528,863 | 303,894 | 266,225 | 299,407 | 451,670 | 2,783,390 | 15,557,477 |
| G-43 | 111,415 | 167,717 | 229,066 | 238,181 | 206,197 | 139,916 | 1,092,492 | 88,052 | 63,990 | 45,226 | 36,726 | 39,261 | 65,735 | 338,990 | 1,431,482 |
| G-51 | 187,448 | 274,514 | 359,907 | 385,766 | 332,045 | 241,900 | 1,781,580 | 177,591 | 155,232 | 132,622 | 120,514 | 128,357 | 140,827 | 855,143 | 2,636,723 |
| G-52 | 223,378 | 294,954 | 368,393 | 347,643 | 326,431 | 252,589 | 1,813,388 | 202,975 | 176,177 | 151,541 | 138,768 | 144,675 | 156,904 | 971,040 | 2,784,427 |
| G-53 | 30,712 | 35,448 | 45,707 | 46,192 | 43,680 | 34,154 | 235,893 | 26,372 | 23,411 | 21,897 | 20,782 | 25,323 | 24,061 | 141,846 | 377,739 |
| G-54 | 641 | 739 | 929 | 919 | 3,772 | 4,964 | 11,964 | 1,280 | 488 | 298 | 134 | 368 | 650 | 3,219 | 15,183 |
| Total C/I | 2,324,800 | 4,343,398 | 6,654,486 | 7,124,430 | 6,187,650 | 4,130,582 | 30,765,347 | 2,192,840 | 1,397,104 | 861,700 | 771,376 | 832,832 | 1,121,232 | 7,177,083 | 37,942,430 |
| **Sales Volume** | **6,103,208** | **11,289,618** | **16,713,541** | **17,879,201** | **15,456,597** | **10,384,290** | **77,826,455** | **5,542,473** | **3,382,001** | **2,114,361** | **1,828,051** | **1,975,945** | **2,814,765** | **17,657,596** | **95,484,050** |
| Transportation Sales | | | | | | | | | | | | | | | |
| G-41 | 346,902 | 592,251 | 849,034 | 903,931 | 829,780 | 592,146 | 4,114,045 | 366,071 | 205,723 | 141,425 | 130,531 | 140,154 | 204,951 | 1,188,854 | 5,302,899 |
| G-42 | 1,193,548 | 1,968,036 | 2,806,411 | 2,952,958 | 2,636,879 | 1,847,163 | 13,404,996 | 1,046,516 | 570,803 | 361,868 | 331,417 | 385,148 | 615,204 | 3,310,956 | 16,715,952 |
| G-43 | 656,809 | 950,554 | 1,194,487 | 1,188,478 | 1,099,782 | 809,158 | 5,899,268 | 498,423 | 317,562 | 203,367 | 222,072 | 250,160 | 394,162 | 1,885,746 | 7,785,014 |
| G-51 | 89,621 | 120,528 | 161,913 | 159,738 | 157,832 | 137,921 | 827,553 | 102,824 | 94,744 | 82,396 | 68,419 | 79,037 | 88,078 | 515,497 | 1,343,050 |
| G-52 | 352,948 | 450,286 | 535,915 | 576,318 | 510,139 | 388,529 | 2,814,135 | 349,729 | 328,175 | 294,883 | 286,867 | 295,232 | 329,890 | 1,884,776 | 4,698,911 |
| G-53 | 809,112 | 957,322 | 1,206,036 | 1,217,486 | 1,072,407 | 913,794 | 6,176,157 | 738,809 | 708,856 | 687,341 | 678,305 | 737,266 | 784,433 | 4,335,008 | 10,511,165 |
| G-54 | 1,284,272 | 1,357,661 | 1,327,986 | 1,571,589 | 1,205,775 | 1,137,421 | 7,884,703 | 1,242,152 | 1,469,596 | 1,375,774 | 1,362,581 | 1,436,585 | 1,449,915 | 8,336,604 | 16,221,307 |
| Total Trans. Sales | **4,733,213** | **6,396,638** | **8,081,781** | **8,570,497** | **7,512,596** | **5,826,133** | **41,120,858** | **4,344,524** | **3,695,459** | **3,147,054** | **3,080,191** | **3,323,582** | **3,866,633** | **21,457,441** | **62,578,299** |
| Total All Sales | **10,836,421** | **17,686,256** | **24,795,322** | **26,449,698** | **22,969,193** | **16,210,423** | **118,947,312** | **9,886,997** | **7,077,460** | **5,261,414** | **4,908,241** | **5,299,526** | **6,681,398** | **39,115,037** | **158,062,349** |

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**ENERGY NORTH NATURAL GAS, INC.**

**Peak 2012 - 2013 Winter Cost of Gas Filing**
**Normal and Design Year Volumes** **Schedule 11A**

**Volumes (Therms)** **Normal Year**

**For the Months of November 12 - April 13**

| | Nov-12 | Dec-12 | Jan-13 | Feb-13 | Mar-13 | Apr-13 | Peak Nov - Apr |
|---|---|---|---|---|---|---|---|
| Pipeline Gas: | | | | | | | |
| Dawn Supply | 924,000 | 926,310 | 954,800 | 862,400 | 954,800 | 820,050 | 5,442,360 |
| Niagara Supply | 721,490 | 745,360 | 745,360 | 672,980 | 745,360 | 721,490 | 4,352,040 |
| TGP Supply (Direct) | 5,292,980 | 5,155,150 | 5,155,150 | 4,656,190 | 5,155,150 | 5,272,190 | 30,686,810 |
| Dracut Supply 1 - Baseload | - | 2,380,840 | 2,380,840 | 2,150,610 | - | - | 6,912,290 |
| Dracut Supply 2 - Swing | 3,531,220 | 957,880 | 1,983,520 | 2,142,140 | 3,002,230 | 3,362,590 | 14,979,580 |
| City Gate Delivered Supply | - | - | - | - | - | - | 0 |
| LNG Truck | 21,560 | 22,330 | 680,680 | - | 44,660 | - | 769,230 |
| Propane Truck | - | - | - | - | - | - | 0 |
| PNGTS | 58,520 | 76,230 | 83,160 | 71,610 | 66,990 | 46,970 | 403,480 |
| Granite Ridge | - | - | - | - | - | - | - |
| Subtotal Pipeline Volumes | 10,549,770 | 10,264,100 | 11,983,510 | 10,555,930 | 9,969,190 | 10,223,290 | 63,545,790 |
| Storage Gas: | | | | | | | |
| TGP Storage | 1,223,530 | 4,811,730 | 5,793,480 | 4,971,120 | 3,670,590 | 52,360 | 20,522,810 |
| Produced Gas: | | | | | | | |
| LNG Vapor | 21,560 | 22,330 | 710,710 | 20,790 | 22,330 | 21,560 | 819,280 |
| Propane | - | - | - | - | - | - | 0 |
| Subtotal Produced Gas | 21,560 | 22,330 | 710,710 | 20,790 | 22,330 | 21,560 | 819,280 |
| Less - Gas Refills: | | | | | | | |
| LNG Truck | (21,560) | (22,330) | (680,680) | - | (44,660) | - | (769,230) |
| Propane | - | - | - | - | - | - | - |
| TGP Storage Refill | (1,851,080) | - | - | - | - | (2,279,200) | (4,130,280) |
| Subtotal Refills | (1,872,640) | (22,330) | (680,680) | - | (44,660) | (2,279,200) | (4,899,510) |
| Total Sendout Volumes | 9,922,220 | 15,075,830 | 17,807,020 | 15,547,840 | 13,617,450 | 8,018,010 | 79,988,370 |

**ENERGY NORTH NATURAL GAS, INC.**

**Peak 2012 - 2013 Winter Cost of Gas Filing**

**Normal and Design Year Volumes** **Schedule 11B**

**Volumes (Therms)** **Design Year**

**For the Months of November 12 - April 13**

| | Nov-12 | Dec-12 | Jan-13 | Feb-13 | Mar-13 | Apr-13 | Peak Nov - Apr |
|---|---|---|---|---|---|---|---|
| Pipeline Gas: | | | | | | | |
| Dawn Supply | 940,381 | 971,727 | 971,727 | 877,689 | 971,727 | 867,501 | 5,600,751 |
| Niagara Supply | 734,281 | 758,574 | 758,574 | 684,911 | 758,574 | 734,281 | 4,429,193 |
| TGP Supply (Direct) | 5,386,031 | 5,246,541 | 5,246,541 | 4,738,736 | 5,246,541 | 5,368,791 | 31,233,180 |
| Dracut Supply 1 - Baseload | - | 2,423,048 | 2,423,048 | 2,188,736 | - | - | 7,034,832 |
| Dracut Supply 2 - Swing | 4,528,717 | 1,728,733 | 3,176,136 | 3,423,770 | 5,390,733 | 4,056,176 | 22,304,265 |
| City Gate Delivered Supply | - | - | - | - | - | - | 0 |
| LNG Truck | 21,942 | 22,726 | 611,248 | 82,283 | 45,452 | - | 783,651 |
| Propane Truck | - | - | 146,543 | 25,077 | - | - | 171,619 |
| PNGTS | 59,557 | 77,581 | 84,634 | 72,880 | 68,178 | 47,803 | 410,633 |
| Granite Ridge | - | - | - | - | - | - | - |
| Other Purchased Resources | - | - | - | - | - | - | - |
| Subtotal Pipeline Volumes | 11,670,909 | 11,228,930 | 13,418,450 | 12,094,081 | 12,481,204 | 11,074,551 | 71,968,125 |
| Storage Gas: | | | | | | | |
| TGP Storage | 1,169,990 | 5,518,468 | 6,297,417 | 5,123,508 | 2,677,734 | 56,423 | 20,843,540 |
| Produced Gas: | | | | | | | |
| LNG Vapor | 21,942 | 22,726 | 611,248 | 133,221 | 22,726 | 21,942 | 833,804 |
| Propane | - | - | 297,004 | 25,077 | - | - | 322,080 |
| Subtotal Produced Gas | 21,942 | 22,726 | 908,251 | 158,297 | 22,726 | 21,942 | 1,155,885 |
| Less - Gas Refills: | | | | | | | |
| LNG Truck | (21,942) | (22,726) | (611,248) | (82,283) | (45,452) | - | (783,651) |
| Propane | - | - | (146,543) | (25,077) | - | - | (171,619) |
| TGP Storage Refill | (1,807,098) | - | - | - | - | (2,264,750) | (4,071,849) |
| Subtotal Refills | (1,829,041) | (22,726) | (757,790) | (107,360) | (45,452) | (2,264,750) | (5,027,119) |
| Total Sendout Volumes | 11,033,801 | 16,747,398 | 19,866,328 | 17,268,526 | 15,136,212 | 8,888,166 | 88,940,431 |

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**ENERGY NORTH NATURAL GAS, INC.** **Schedule 11C**

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**Peak 2012 - 2013 Winter Cost of Gas Filing**

**Capacity Utilization**

**Volumes (Therms)**

| | Peak Period Normal Year Use (Therms) | MDQ (MMBtu/day) | Seasonal Quantity (Therms) | Utilization Rate | Peak Period Design Year Use (Therms) | MDQ (MMBtu/day) | Seasonal Quantity (Therms) | Utilization Rate |
|---|---|---|---|---|---|---|---|---|
| **Pipeline Gas:** | | | | | | | | |
| Dawn Supply | 5,442,360 | 4,000 | 7,240,000 | 75% | 5,600,751 | 4,000 | 7,240,000 | 77% |
| Niagara Supply | 4,352,040 | 3,122 | 5,650,820 | 77% | 4,429,193 | 3,122 | 5,650,820 | 78% |
| TGP Supply (Direct) | 30,686,810 | 21,596 | 39,088,760 | 79% | 31,233,180 | 21,596 | 39,088,760 | 80% |
| Dracut Supply 1 & 2 | 21,891,870 | 50,000 | 90,500,000 | 24% | 29,339,097 | 50,000 | 90,500,000 | 32% |
| LNG Truck | 769,230 | - | - | - | 783,651 | - | - | - |
| Propane Truck | - | - | - | - | 171,619 | - | - | - |
| PNGTS | 403,480 | 1,000 | 1,810,000 | 22% | 410,633 | 1,000 | 1,810,000 | 23% |
| Granite Ridge | - | - | - | - | - | - | - | - |
| Other Purchased Resources | - | - | - | - | - | - | - | - |
| Subtotal Pipeline Volumes | 63,545,790 | | | | 71,968,125 | | | |
| **Storage Gas:** | | | | | | | | |
| TGP Storage | 20,522,810 | | 25,801,310 | 80% | 20,843,540 | | 25,801,310 | 81% |
| **Produced Gas:** | | | | | | | | |
| LNG Vapor | 819,280 | | | | 833,804 | | | |
| Propane | - | | | | 322,080 | | | |
| Subtotal Produced Gas | 819,280 | | | | 1,155,885 | | | |
| **Less - Gas Refills:** | | | | | | | | |
| LNG Truck | (769,230) | | | | (783,651) | | | |
| Propane | - | | | | (171,619) | | | |
| TGP Storage Refill | (4,130,280) | | | | (4,071,849) | | | |
| Subtotal Refills | (4,899,510) | | | | (5,027,119) | | | |
| Total Sendout Volumes | 79,988,370 | | | | 88,940,431 | | | |

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**ENERGY NORTH NATURAL GAS, INC.** **Schedule 11D**

**Peak 2012 - 2013 Winter Cost of Gas Filing**

Forecast of Upcoming Winter Period
Design Day Report
2012 / 13 Heating Season
(Therms)

EnergyNorth Natural Gas, Inc.
d/b/a National Grid New Hampshire

72 HDD at Manchester, N.H.

| | |
|---|---|
| **Requirements** | |
| Firm Sales | 1,133,557 |
| Interruptible Sales | 0 |
| Firm Transportation | 246,443 |
| Interruptible Transportation | 0 |
| Total Requirements | 1,380,000 |
| **Resources** | |
| Purchased Pipeline Gas | 643,600 |
| Underground Storage Gas | 281,100 |
| Propane Air Production | 350,000 |
| LNG Produced Gas | 105,300 |
| Third-Party Supply | 0 |
| Total Resources | 1,380,000 |

Please refer to the ENGI 2010 IRP filing (DG 10-041) for a complete description of the methodology and assumptions used in the derivation of this data.

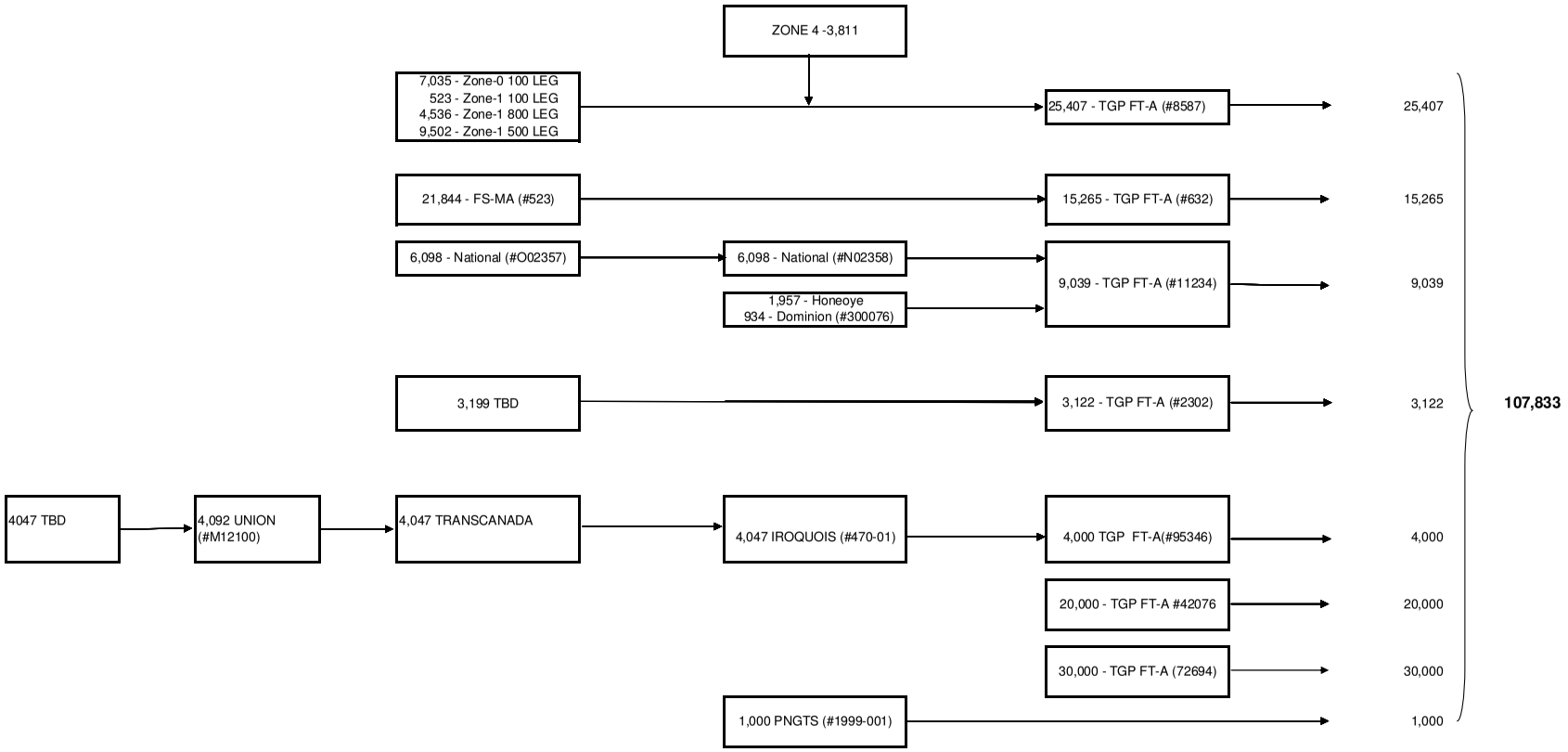
Preparation of this report was supervised by:

Theodore Poe, Jr.
Manager, Energy Planning

Note: Forecasted Firm Transportation volumes are for customers using utility capacity only.

**ENERGY NORTH NATURAL GAS, INC.**

**Peak 2012 - 2013 Winter Cost of Gas Filing**
**Transportation Available for Pipeline Supply and Storage**
**(MMBtu)**



**ENERGY NORTH NATURAL GAS, INC.**

**Peak 2012 - 2013 Winter Cost of Gas Filing**
**Agreements for Gas Supply and Transportation**

| SOURCE | RATE SCHEDULE | CONTRACT NUMBER | TYPE | MDQ MMBTU | MAQ * MMBTU | EXPIRATION DATE | NOTIFICATION DATE | RENEWAL OPTIONS |
|---|---|---|---|---|---|---|---|---|
| Granite Ridge Energy, LLC EXPIRES (Formerly AES Londonderry, L.L.C.) | - | - | Supply | 15,000 | 450,000 | 09/30/2012 | N/a | Mutually agreed upon. |
| Montly Purchase - TBD No Off-Peak | - | - | Supply | 3,199 | 1,167,635 | 03/31/2012 | N/a | Terminates |
| TBD - No Off-Peak Sent RFP | - | - | Supply | 4,047 | 611,097 | Peak Only | N/a | Terminates |
| Distrigas of Massachusetts Corp. Renew Need to negotiate | FLS | FLS183 | Liquid Refill | Up to 3 trucks | 100,000 National Grid Total | 03/31/2012 Peak Only | - | Terminates |
| Repsol AMA | - | - | Supply | April 2012 = 10,000 / day | 4,491,000 | 04/30/2012 | - | Terminates |
| Montly Purchase - TBD | - | - | Supply | 21,596 | 3,908,876 | 04/30/2012 | N/a | Terminates |
| Eastern Propane Gas Need to negotiate (Trucking Contract and Maybe Supply) | | | Trucking | 28,500 Gallons | 900,000 Gallons | 03/31/2012 | N/a | Terminates |
| Dominion Transmission Incorporated | GSS | 300076 | Storage | 934 | 102,700 | 03/31/2016 | 03/31/2013 | Mutually agreed upon |
| Honeoye Storage Corporation | SS-NY | - | Storage | 1,957 | 246,240 | 04/01/2013 | 12 months notice | Evergreen Provision |
| National Fuel Gas Supply Corporation | FSS | O02358 | Storage | 6,098 | 670,800 | 03/31/2013 | 03/31/2013 | Evergreen Provision |
| National Fuel Gas Supply Corporation | FSST | N02358 | Transportation | 6,098 | 670,800 | 03/31/2013 | 03/31/2013 | Evergreen Provision |
| Iroquois Gas Transmission System | RTS-1 | 47001 | Transportation | 4,047 | 1,477,155 | 11/01/2017 | 10/31/2012 | Evergreen Provision |
| Portland Natural Gas Transmission System | FT 1999-01 | 1999-001 | Transportation | 1,000 | 365,000 | 10/31/2019 | 10/31/2018 | Evergreen Provision |
| Tennessee Gas Pipeline Company | FS-MA | 523 | Storage | 21,844 | 1,560,391 | 10/31/2015 | 10/31/2012 | Evergreen Provision |
| Tennessee Gas Pipeline Company | FTA | 8587 | Transportation | 25,407 | 9,273,555 | 10/31/2015 | 10/31/2012 | Evergreen Provision |
| Tennessee Gas Pipeline Company | FTA | 2302 | Transportation | 3,122 | 1,139,530 | 10/31/2015 | 10/31/2012 | Evergreen Provision |
| Tennessee Gas Pipeline Company | FTA | 632 | Transportation | 15,265 | 5,571,725 | 10/31/2015 | 10/31/2012 | Evergreen Provision |
| Tennessee Gas Pipeline Company | FTA | 11234 | Transportation | 9,039 | 3,299,235 | 10/31/2015 | 10/31/2012 | Evergreen Provision |
| Tennessee Gas Pipeline Company | FTA | 72694 | Transportation | 30,000 | 10,950,000 | 10/31/2029 | 10/31/2029 | Evergreen Provision |
| Tennessee Gas Pipeline Company | FTA | 95346 | Transportation | 4,000 | 1,460,000 | 11/30/2012 | 10/31/2012 | Evergreen Provision |
| Tennessee Gas Pipeline Company | FTA | 42076 | Transportation | 20,000 | 7,300,000 | 10/31/2015 | 10/31/2012 | Evergreen Provision |
| TransCanada Pipeline | FT | | Transportation | 4,047 | 1,477,155 | 10/31/2017 | 04/30/2016 | Evergreen Provision |
| Union Gas Limited | M12 | M12100 | Transportation | 4,092 | 1,493,580 | 10/31/2017 | 10/31/2015 | Evergreen Provision |

* MAQ is calculated on a 365 day calendar year.

**ENERGY NORTH NATURAL GAS, INC.**

**Peak 2012 - 2013 Winter Cost of Gas Filing**
**Load Migration From Sales to Transportation in the C&I High and Low Winter Use Classes**

**May 2011 - Apr 2012 Normalized Sales and Transportation Volumes (Therms)**

| C&I Rate Classes | Annual Sales | % of Total by Class | % of Sales to Total Volume by Class |
|---|---|---|---|
| G-41 | 14,331,712 | 38.37% | 77.36% |
| G-42 | 15,403,573 | 41.24% | 50.97% |
| G-43 | 1,251,018 | 3.35% | 15.24% |
| G-51 | 2,764,675 | 7.40% | 73.97% |
| G-52 | 3,190,891 | 8.54% | 45.77% |
| G-53 | 392,113 | 1.05% | 4.21% |
| G-54 | 15,437 | 0.04% | 0.09% |
| Total C/I | 37,349,418 | 100.00% | |

| | Annual Transportation | % of Total by Class | % of Transportation to Total Volume by Class |
|---|---|---|---|
| G-41 | 4,194,419 | 7.49% | 22.64% |
| G-42 | 14,816,927 | 26.46% | 49.03% |
| G-43 | 6,955,718 | 12.42% | 84.76% |
| G-51 | 972,759 | 1.74% | 26.03% |
| G-52 | 3,780,622 | 6.75% | 54.23% |
| G-53 | 8,921,064 | 15.93% | 95.79% |
| G-54 | 16,358,087 | 29.21% | 99.91% |
| Total C/I | 55,999,596 | 100.00% | |

| Sales & Transportation | Total | % of Total by Class | |
|---|---|---|---|
| G-41 | 18,526,131 | 19.85% | 100.00% |
| G-42 | 30,220,501 | 32.37% | 100.00% |
| G-43 | 8,206,736 | 8.79% | 100.00% |
| G-51 | 3,737,433 | 4.00% | 100.00% |
| G-52 | 6,971,513 | 7.47% | 100.00% |
| G-53 | 9,313,176 | 9.98% | 100.00% |
| G-54 | 16,373,523 | 17.54% | 100.00% |
| Total C/I | 93,349,014 | 100.00% | |

**ENERGY NORTH NATURAL GAS, INC.**

**Peak 2012 - 2013 Winter Cost of Gas Filing**
**Delivered Costs of Winter Supplies to Pipeline Delivered Supplies from the Prior Year**

| | Off-Peak May 11 - Oct 11 (Therms) | Peak Nov 11-Apr 12 (Therms) | Total May 11 - Apr 12 (Therms) |
|---|---|---|---|
| Pipeline Deliveries | 16,235,690 | 62,165,410 | 78,401,100 |
| All Others | 495,940 | 5,944,570 | 6,440,510 |
| | 16,731,630 | 68,109,980 | 84,841,610 |

| | Ratio |
|---|---|
| Total Winter Supplies | 68,109,980 |
| Total Pipeline Deliveries | 78,401,100 |
| Ratio Winter Supplies to Pipeline Supplies | 0.869 |

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**ENERGY NORTH NATURAL GAS, INC.**

**Peak 2012 - 2013 Winter Cost of Gas Filing**
**July and August Consumption of C&I High and Low Winter Classes as a Percentage of Their Annual Consumption**

| **C&I Sales Normalized (Therms)** | **Jul-11** | **Aug-11** | **Jul - Aug Total** | **Total Annual** | **% of Jul-Aug to Total** |
|---|---|---|---|---|---|
| (a) | (b) | (c) | (e)=(c)+(d) | (f) | (g)=(e)/(f) |
| G-41 | 203,496 | 154,227 | 357,723 | 14,331,712 | 2.50% |
| G-42 | 341,785 | 272,667 | 614,452 | 15,403,573 | 3.99% |
| G-43 | 33,989 | 35,316 | 69,305 | 1,251,018 | 5.54% |
| G-51 | 154,920 | 134,687 | 289,607 | 2,764,675 | 10.48% |
| G-52 | 204,251 | 186,110 | 390,361 | 3,190,891 | 12.23% |
| G-53 | 23,759 | 20,389 | 44,148 | 392,113 | 11.26% |
| G-54 | 881 | 861 | 1,742 | 15,437 | 11.28% |
| Total C/I | 963,081 | 804,257 | 1,767,338 | 37,349,418 | 4.73% |

**ENERGY NORTH NATURAL GAS, INC.**

**Peak 2012 - 2013 Winter Cost of Gas Filing**
**Storage Inventory, Undergound, LPG and LNG including Calculation of Money Pool Interest Costs Associated with Natural Gas**

**Underground Storage Gas**

| | | May-12 (Actual) | Jun-12 (Actual) | Jul-12 (Estimate) | Aug-12 (Estimate) | Sep-12 (Estimate) | Oct-12 (Estimate) | Nov-12 (Estimate) | Dec-12 (Estimate) | Jan-13 (Estimate) | Feb-13 (Estimate) | Mar-13 (Estimate) | Apr-13 (Estimate) | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Beginning Balance (MMBtu) | | 1,895,479 | 1,901,645 | 1,929,241 | 1,929,241 | 1,929,241 | 2,113,358 | 2,297,475 | 2,360,230 | 1,879,057 | 1,299,709 | 802,597 | 435,538 | 1,895,479 |
| Injections (MMBtu) | Sch 11A ln 37 /10 | 11,436 | 27,746 | - | - | 184,117 | 184,117 | 185,108 | - | - | - | - | 227,920 | 820,444 |
| Subtotal | | 1,906,915 | 1,929,391 | 1,929,241 | 1,929,241 | 2,113,358 | 2,297,475 | 2,482,583 | 2,360,230 | 1,879,057 | 1,299,709 | 802,597 | 663,458 | |
| Storage Sale | | - | | | | | - | | | | | | | |
| Withdrawals (MMBtu) | Sch 11A ln 27 /10 | (5,270) | (150) | - | - | - | - | (122,353) | (481,173) | (579,348) | (497,112) | (367,059) | (5,236) | (2,057,701) |
| Ending Balance (MMBTu) | | 1,901,645 | 1,929,241 | 1,929,241 | 1,929,241 | 2,113,358 | 2,297,475 | 2,360,230 | 1,879,057 | 1,299,709 | 802,597 | 435,538 | 658,222 | 658,222 |
| | | | | | | | | | | | | | | |
| Beginning Balance | | $ 9,092,272 | $ 9,085,950 | $ 9,164,894 | $ 9,164,894 | $ 9,164,894 | $ 9,773,400 | $ 10,386,322 | $ 10,491,583 | $ 8,352,695 | $ 5,777,405 | $ 3,567,666 | $ 1,936,033 | 9,092,272 |
| Injections | ln 11 * ln 36 | 18,859 | 78,943 | - | - | 608,506 | 612,922 | 649,138 | - | - | - | - | 886,634 | 2,855,003 |
| Subtotal | | $ 9,111,130 | $ 9,164,894 | $ 9,164,894 | $ 9,164,894 | $ 9,773,400 | $ 10,386,322 | $ 11,035,460 | $ 10,491,583 | $ 8,352,695 | $ 5,777,405 | $ 3,567,666 | $ 2,822,667 | |
| Storage Sale | | $ - | | | | | $ - | | | | | | | |
| Withdrawals | ln 17 * ln 34 | $ (25,180) | $ - | $ - | $ - | $ - | $ - | $ (543,878) | $ (2,138,887) | $ (2,575,290) | $ (2,209,739) | $ (1,631,633) | $ (22,276) | (9,146,884) |
| Ending Balance | | $ 9,085,950 | $ 9,164,894 | $ 9,164,894 | $ 9,164,894 | $ 9,773,400 | $ 10,386,322 | $ 10,491,583 | $ 8,352,695 | $ 5,777,405 | $ 3,567,666 | $ 1,936,033 | $ 2,800,391 | $ 2,800,391 |
| Average Rate For Withdrawals | ln 22 /ln 9 | $4.7779 | $4.7501 | $4.7505 | $4.7505 | $4.6246 | $4.5208 | $4.4452 | $4.4452 | $4.4452 | $4.4452 | $4.4452 | $4.2545 | |
| TGP Storage Rate for Injections | Actual or NYMEX plus TGP Transportation | $1.6490 | $2.8452 | $0.0000 | $0.0000 | $3.3050 | $3.3290 | $3.5068 | $3.7824 | $3.9169 | $3.9312 | $3.9108 | $3.8901 | |

| For Informational Purposes | Nov-12 | Dec-12 | Jan-13 | Feb-13 | Mar-13 | Apr-13 | Total |
|---|---|---|---|---|---|---|---|
| Summer Hedge Contracts - Vols Dth | - | - | - | - | - | - | - |
| Average Hedge Price | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | |
| NYMEX | $3.1057 | $3.3715 | $3.5012 | $3.5151 | $3.4954 | $3.4754 | |
| Hedged Volumes at Hedged Price | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Less Hedged Volumes at NYMEX | - | - | - | - | - | - | - |
| Hedge (Savings)/Loss | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Month Dollar Average | ln (22 + ln 32) /2 | $ 9,164,894 | $ 9,469,147 | $ 10,079,861 | $ 10,438,952 | $ 9,422,139 | $ 7,065,050 | $ 4,672,536 | $ 2,751,850 | $ 2,368,212 | | | | |
| Money Pool Finance Rate (per Nov 10 - Apr 11 Actuals) | | 0.80% | 1.29% | 1.37% | 1.35% | 1.40% | 1.51% | 1.61% | 1.62% | 1.56% | | | | |
| Inventory Finance Charge | ln 47 * ln 49 | $ 6,099 | $ 10,209 | $ 11,528 | $ 11,780 | $ 11,004 | $ 8,870 | $ 6,263 | $ 3,718 | $ 3,088 | | | | |
| Financial Expenses | | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | | | | |
| Total Inventory Finance Charges | | $ 6,599 | $ 10,709 | $ 12,028 | $ 12,280 | $ 11,504 | $ 9,370 | $ 6,763 | $ 4,218 | $ 3,588 | | | | |

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**ENERGY NORTH NATURAL GAS, INC.**

**Peak 2012 - 2013 Winter Cost of Gas Filing**
**Storage Inventory, Undergound, LPG and LNG including Calculation of Money Pool Interest Costs Associated with Natural Gas**

**Liquid Propane Gas (LPG)**

| | | May-12 (Actual) | Jun-12 (Actual) | Jul-12 (Estimate) | Aug-12 (Estimate) | Sep-12 (Estimate) | Oct-12 (Estimate) | Nov-12 (Estimate) | Dec-12 (Estimate) | Jan-13 (Estimate) | Feb-13 (Estimate) | Mar-13 (Estimate) | Apr-13 (Estimate) | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Beginning Balance | | 93,824 | 93,828 | 94,844 | 94,844 | 94,844 | 94,844 | 94,844 | 94,844 | 94,844 | 94,844 | 94,844 | 94,844 | 93,824 |
| Injections | Sch 11A ln 36 /10 | 72 | 1,016 | - | - | - | - | - | - | - | - | - | - | 1,088 |
| Subtotal | | 93,896 | 94,844 | 94,844 | 94,844 | 94,844 | 94,844 | 94,844 | 94,844 | 94,844 | 94,844 | 94,844 | 94,844 | |
| Withdrawals | Sch 11A ln 31 /10 | (68) | - | - | - | - | - | - | - | - | - | - | - | (68) |
| Adjustment for change in temperature | | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Adjustment for Transfer | | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Ending Balance | | 93,828 | 94,844 | 94,844 | 94,844 | 94,844 | 94,844 | 94,844 | 94,844 | 94,844 | 94,844 | 94,844 | 94,844 | 94,844 |
| | | | | | | | | | | | | | | |
| Beginning Balance | | $ 1,382,938 | $ 1,382,997 | $ 1,396,098 | $ 1,406,774 | $ 1,406,774 | $ 1,406,774 | $ 1,406,774 | $ 1,406,774 | $ 1,406,774 | $ 1,406,774 | $ 1,406,774 | $ 1,406,774 | $ 1,382,938 |
| Injections | ln 45 * ln 68 | 1,061 | 13,101 | - | - | - | - | - | - | - | - | - | - | 14,162 |
| Subtotal | | $ 1,384,000 | $ 1,396,098 | $ 1,396,098 | $ 1,406,774 | $ 1,406,774 | $ 1,406,774 | $ 1,406,774 | $ 1,406,774 | $ 1,406,774 | $ 1,406,774 | $ 1,406,774 | $ 1,406,774 | |
| Withdrawals | ln 51 * ln 66 | (1,002) | - | 10,676 | - | - | - | - | - | - | - | - | - | 9,674 |
| Ending Balance | | $ 1,382,997 | $ 1,396,098 | $ 1,406,774 | $ 1,406,774 | $ 1,406,774 | $ 1,406,774 | $ 1,406,774 | $ 1,406,774 | $ 1,406,774 | $ 1,406,774 | $ 1,406,774 | $ 1,406,774 | $ 1,406,774 |
| | | | | | | | | | | | | | | |
| Average Rate For Withdrawals | | $14.7397 | $14.7199 | $14.7199 | $14.8325 | $14.8325 | $14.8325 | $14.8325 | $14.8325 | $14.8325 | $14.8325 | $14.8325 | $14.8325 | |
| | | | | | | | | | | | | | | |
| Propane Rate for Injections | Actual or Sch. 6, ln 151 * 10 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | |
| | | | | | | | | | | | | | | |
| Month Dollar Average | ln (56 + ln 64) /2 | | | | $ 1,406,774 | $ 1,406,774 | $ 1,406,774 | $ 1,406,774 | $ 1,406,774 | $ 1,406,774 | $ 1,406,774 | $ 1,406,774 | $ 1,406,774 | |
| Money Pool Finance Rate (per Nov 10 - Apr 11 Actuals) | | | | | 0.80% | 1.29% | 1.37% | 1.35% | 1.40% | 1.51% | 1.61% | 1.62% | 1.56% | |
| Inventory Finance Charge | ln 71 * ln 73 | | | | $ 936 | $ 1,517 | $ 1,609 | $ 1,588 | $ 1,643 | $ 1,766 | $ 1,886 | $ 1,901 | $ 1,834 | |

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**ENERGY NORTH NATURAL GAS, INC.**

**Peak 2012 - 2013 Winter Cost of Gas Filing**
**Storage Inventory, Undergound, LPG and LNG including Calculation of Money Pool Interest Costs Associated with Natural Gas**

| **Liquid Natural Gas (LNG)** | | May-12 (Actual) | Jun-12 (Actual) | Jul-12 (Estimate) | Aug-12 (Estimate) | Sep-12 (Estimate) | Oct-12 (Estimate) | Nov-12 (Estimate) | Dec-12 (Estimate) | Jan-13 (Estimate) | Feb-13 (Estimate) | Mar-13 (Estimate) | Apr-13 (Estimate) | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Beginning Balance | | 7,885 | 5,928 | 10,583 | 10,583 | 10,583 | 10,583 | 10,583 | 10,583 | 10,583 | 7,580 | 5,501 | 7,734 | 7,885 |
| Injections | Sch 11A ln 35 /10 | 797 | 6,395 | - | - | - | - | 2,156 | 2,233 | 68,068 | - | 4,466 | - | 84,115 |
| Subtotal | | 8,682 | 12,323 | 10,583 | 10,583 | 10,583 | 10,583 | 12,739 | 12,816 | 78,651 | 7,580 | 9,967 | 7,734 | |
| Withdrawals | Sch 11A ln 30 /10 | (2,754) | (1,740) | - | - | - | - | (2,156) | (2,233) | (71,071) | (2,079) | (2,233) | (2,156) | (86,422) |
| Ending Balance | | 5,928 | 10,583 | 10,583 | 10,583 | 10,583 | 10,583 | 10,583 | 10,583 | 7,580 | 5,501 | 7,734 | 5,578 | 5,578 |
| | | | | | | | | | | | | | | |
| Beginning Balance | | $ 34,430 | $ 25,885 | $ 42,850 | $ 42,850 | $ 42,850 | $ 42,850 | $ 42,850 | $ 41,161 | $ 40,206 | $ 26,843 | $ 19,481 | $ 27,229 | $ 34,430 |
| Injections | ln 76 * ln 97 | 3,480 | 24,011 | - | - | - | - | 6,696 | 7,528 | 238,320 | - | 15,610 | - | 295,645 |
| Subtotal | | $ 37,910 | $ 49,896 | $ 42,850 | $ 42,850 | $ 42,850 | $ 42,850 | $ 49,546 | $ 48,689 | $ 278,526 | $ 26,843 | $ 35,091 | $ 27,229 | |
| Withdrawals | ln 80 * ln 95 | (12,025) | (7,045) | - | - | - | - | (8,385) | (8,483) | (251,683) | (7,362) | (7,862) | (7,591) | (310,437) |
| Ending Balance | | $ 25,885 | $ 42,850 | $ 42,850 | $ 42,850 | $ 42,850 | $ 42,850 | $ 41,161 | $ 40,206 | $ 26,843 | $ 19,481 | $ 27,229 | $ 19,639 | $ 19,639 |
| | | | | | | | | | | | | | | |
| Average Rate For Withdrawals | | $4.3665 | $4.0490 | $4.0490 | $4.0490 | $4.0490 | $4.0490 | $3.8893 | $3.7991 | $3.5413 | $3.5413 | $3.5207 | $3.5207 | |
| | | | | | | | | | | | | | | |
| LNG Rate for Injections | Actual or Sch. 6, ln 150 * 10 | $4.3665 | $3.7546 | $3.5012 | $3.5151 | $3.4954 | $3.4754 | $3.1057 | $3.3715 | $3.5012 | $3.5151 | $3.4954 | $3.4754 | |
| | | | | | | | | | | | | | | |
| Month Dollar Average | ln (85 + ln 93) /2 | | | | $ 42,850 | $ 42,850 | $ 42,850 | $ 42,006 | $ 40,683 | $ 33,524 | $ 23,162 | $ 23,355 | $ 23,434 | |
| Money Pool Finance Rate (per Nov 10 - Apr 11 Actuals) | | | | | 0.80% | 1.29% | 1.37% | 1.35% | 1.40% | 1.51% | 1.61% | 1.62% | 1.56% | |
| Inventory Finance Charge | ln 100 * ln 102 | | | | $ 29 | $ 46 | $ 49 | $ 47 | $ 48 | $ 42 | $ 31 | $ 32 | $ 31 | |
| | | | | | | | | | | | | | | |
| Total Fuel Financing | Ins 53 + 75 + 104 | | | | $ 7,564 | $ 12,272 | $ 13,686 | $ 13,915 | $ 13,194 | $ 11,178 | $ 8,679 | $ 6,151 | $ 5,453 | |

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**ENERGY NORTH NATURAL GAS, INC.**

**Peak 2012 - 2013 Winter Cost of Gas Filing**
**Forecast of Firm Transportation Volumes and Cost of Gas Revenues**

**Firm Transportation**

| | Therms 1/ | Cost of Gas Rate 2/ | Cost of Gas Revenue |
|---|---|---|---|
| Nov-12 | 4,733,213 | $0.0002 | $ 947 |
| Dec-12 | 6,396,638 | 0.0002 | 1,279 |
| Jan-13 | 8,081,781 | 0.0002 | 1,616 |
| Feb-13 | 8,570,497 | 0.0002 | 1,714 |
| Mar-13 | 7,512,596 | 0.0002 | 1,503 |
| Apr-13 | 5,826,133 | 0.0002 | 1,165 |
| Total | **41,120,858** | | **$ 8,224** |

1/ Per Schedule 10B, line 35. Excludes special contract volumes subject to transportation cost of gas.
2/ Refer to Proposed First Revised Page 89 for calculation of rate.

# Liberty Utilities

ChristiAne Mason
Director/Head
Regulatory, Government & Community
C: 603-856-4231
E: ChristiAne.Mason@libertyutilities.com

July 27, 2012

***Via Electronic Mail and U.S. Mail***

Debra Howland, Executive Director
New Hampshire Public Utilities Commission
21 South Fruit Street, Suite 10
Concord, NH 03301-2429

Re: DG 11-192
EnergyNorth Natural Gas, Inc.
2011-12 Winter Period Cost of Gas Reconciliation
REDACTED

Dear Ms. Howland:

Enclosed are seven copies of the redacted version of the 2011-12 Winter Period Cost of Gas reconciliation filing for EnergyNorth Natural Gas, Inc. ("the Company"). This filing is being submitted under protective order and confidential treatment granted by the Commission in Order No. 25,286 dated October 31, 2011 in Docket DG 11-192. This report has been filed electronically with the New Hampshire Public Utilities Commission in accordance with Order Number 24,223 issued on October 24, 2003, in which the Commission found that the filing requirement would be satisfied by filing one electronic copy and one paper copy with the Commission. The Company has also filed separately a confidential version with the Commission.

The filing shows an under collection for the 2011-12 Winter Period of $1,606,569 summarized as follows:

| | |
|---|---|
| Winter Period Beginning Balance | $3,735,297 |
| Less: Cost of Gas Revenue Billed | ($47,440,335) |
| Add: Cost of Gas Allowable (5/1/11 -10/31/11) | $1,890,001 |
| Add: Cost of Gas Allowable (11/1/11 -4/30/12) | $43,421,606 |
| Winter Period Ending Balance | $1,606,569 |

This filing consists of a six-page summary and nine supporting schedules. Page 1 of the Summary compares the actual deferred gas costs to the projections submitted in the Company's filing including the beginning balance, interest and other allowable adjustments to gas costs, gas costs and gas cost revenue. The result is a net under collection of $1,606,569. Page 2 of the Summary compares the actual allowed Bad Debt and Working Capital costs to the filed projections submitted in the Company's filing resulting in an under collection of $113,348 and an over collection of $541, respectively, for a net under

collection for all the gas accounts of $1,719,376. Page 3 of the Summary compares actual demand charges of $9,753,327 to the $12,917,335 in demand charges estimated in the filing. Page 4 shows a similar comparison for commodity costs. The actual commodity costs were $35,119,541 compared to $46,765,731 in the filing. The $11,646,190 decrease in commodity costs was caused mainly by lower prices than originally forecasted. The results show that the actual demand and commodity costs were $14,810,198 lower than filed. Page 5 of the Summary provides a variance analysis that explains how much of the difference between actual costs and forecasted costs is due to weather ($3,447,242) changes in demand ($7,743,150) and changes in gas prices ($3,619,807). Page 6 of the Summary shows the calculation of the actual Transportation Cost of Gas Revenue compared to the filing.

The attached Schedule 1 provides a monthly summary of the deferred gas cost account balances including beginning balances, actual gas cost allowable, gas cost collections, and interest applied. Schedule 1A provides the same information for bad debt associated with the cost of gas. Schedule 2 provides the details of gas cost by source. Schedule 3 provides the detailed calculation of winter gas cost revenue billed by rate class. Schedule 4 provides a monthly summary of the non-firm margin and capacity release credits to the winter cost of gas account. Schedule 5 provides the monthly summary of the deferred gas cost balances associated with gas working capital. It shows the monthly beginning account balances, working capital allowable, the working capital collections and the interest applied to derive the monthly ending balances. Schedule 6 shows the bad debt and working capital calculation that determines the amount of expense booked for those items. Schedule 7 provides the backup calculations for the revenue billed to recover working capital and bad debt by rate class. Schedule 8 provides a summary of the monthly commodity costs and related volumes. Schedule 9 provides a summary of the monthly prime interest rates used to calculate the interest on the deferred balances.

Please return one copy of this filing to me bearing the Commission's receipt stamp in the envelope that has been provided for your convenience.

Please do not hesitate to contact me with questions regarding this filing.

Sincerely,

ChristiAne G. Mason

Enclosure

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ocalitigation@oca.nh.gov

**ENERGY NORTH NATURAL GAS, INC**

**WINTER 2011-2012 COST OF GAS RESULTS**
**DG 11-192**
**NOVEMBER 2011 THROUGH APRIL 2012**

| | Original Filing 1/ | Actual | | Difference |
|---|---|---|---|---|
| **Peak Gas cost Account 175.20** | | | | |
| Balance 05/01/11 - (Over) / Under | $3,735,297 | $3,735,297 | 2/ | ($0) |
| Peak Gas Costs 5/1/11 - 10/31/11 | $3,557,973 | $3,307,565 | 3/ | (250,408) |
| Fuel Financing 5/1/11 - 10/31/11 | 80,980 | 37,301 | 3/ | (43,679) |
| Prior Period Adjustment 5/1/10-10/31/10 | - | (43,023) | 3/ | (43,023) |
| Broker Revenue 5/1/11 - 10/31/11 | (987,254) | (764,952) | 3/ | 222,302 |
| 280 Day Margins 5/1/11 - 10/31/11 | - | - | 4/ | - |
| IT Sales Margins 5/1/11 - 10/31/11 | - | - | 4/ | - |
| Off System Sales Margin 5/1/11 - 10/31/11 | (44,872) | (67,043) | 4/ | (22,171) |
| Capacity Release 5/1/11 - 10/31/11 | (311,822) | (653,025) | 4/ | (341,203) |
| Interest 5/1/11 - 10/31/11 | 78,435 | 73,178 | 3/ | (5,257) |
| Sum 5/1/11 - 10/31/11 costs | $2,373,440 | $1,890,001 | | ($483,439) |
| Beginning Balance 10/31/11 (Over)/Under | $6,108,737 | $5,625,298 | | ($483,439) |
| Interest 11/1/11 - 4/30/12 | 42,152 | 59,360 | | 17,208 |
| Prior Period Adjustments | - | - | | 0 |
| Interruptible Sales Margin 11/1/11 - 4/30/12 | - | - | | - |
| 280-Day Margin 11/1/11 - 4/30/12 | - | - | | - |
| Off System Sales Margin 11/1/10 -4/30/11 | (95,170) | (9,497) | | 85,673 |
| Capacity Release Credits 11/1/11 - 4/30/12 | (19,280) | (40,749) | | (21,469) |
| Other Transportation Related Margins | 0 | 0 | | 0 |
| Fixed Price Option Admin Costs | 40,691 | 0 | | (40,691) |
| Broker Revenues 11/1/11 - 4/30/12 | (430,318) | (250,791) | | 179,527 |
| Production & Storage | 1,980,428 | 1,980,428 | | 0 |
| Misc Overhead | 10,337 | 10,337 | | 0 |
| Fuel Financing 11/1/11 - 4/30/12 | 101,995 | 107,214 | | 5,219 |
| Transportation Cost of Gas Revenue | - | - | | - |
| Total Adjustment to Costs | $1,630,835 | $1,856,303 | | $225,468 |
| Gas Costs 11/1/11 - 4/30/12 | $56,125,094 | $41,565,303 | | ($14,559,791) |
| Total Gas Costs and Adjustments 11/11 - 04/12 | $57,755,929 | $43,421,606 | | ($14,334,323) |
| Gas Cost Billed | ($63,864,666) | (47,440,335) | | $16,424,331 |
| Total (Over) / Under 04/30/12 | $0 | $1,606,569 | | $1,606,569 |

Prepared By: Kevin Baxter
Reviewed By: Robert Campbell

**ENERGY NORTH NATURAL GAS, INC**

**WINTER 2011-2012 COST OF GAS RESULTS**
**DG 11-192**
**NOVEMBER 2011 THROUGH APRIL 2012**

| | Original Filing 1/ | Actual | | Difference |
|---|---|---|---|---|
| **Bad Debts Account 175.52** | $36,020 | $36,020 | | $0 |
| | 84,431 | 64,770 | 5/ | (19,661) |
| Beginning Balance | 1,281 | (279) | 5/ | (1,560) |
| BD Costs 5/1/11 - 10/31/11 | $121,732 | $228,246 | | ($21,221) |
| Interest 5/1/11 - 10/31/11 | | | | |
| Beginning Balance 10/31/11 (Over)/Under | 1,420,593 | 1,132,153 | | (288,440) |
| Bad Debt Costs 11/1/11 - 4/30/12 | (1,543,183) | (1,249,713) | | 293,470 |
| Bad Debt CGA Billed | - | - | | 0 |
| Adjustment | 858 | 2,662 | | 1,804 |
| Interest | $0 | $113,348 | | $113,348 |
| Total (Over) / Under 04/30/12 | | | | |
| **Working Capital Account 142.20** | $8,916 | $8,916 | | ($0) |
| | 4,522 | 3,288 | 6/ | (1,234) |
| Beginning Balance | 179 | 168 | 6/ | (11) |
| WC Costs 5/1/11 - 10/31/11 | $13,617 | $12,372 | | ($1,245) |
| Interest 5/1/11 - 10/31/11 | | | | |
| Beginning Balance 10/31/11 (Over)/Under | 71,328 | 52,761 | | (18,567) |
| Working Capital Costs 11/1/11 - 4/30/12 | (85,065) | (65,772) | | 19,293 |
| Working Capital CGA Billed | - | - | | 0 |
| Adjustment | 120 | 98 | | (22) |
| Interest | $0 | ($541) | | ($541) |
| Total (Over) / Under 04/30/12 | $0 | $1,719,376 | | $1,719,376 |
| **Total 175.20, 175.52, 142.20** | | | | |

1/ As filed 09-01-11 in the Winter 2011-2012 Cost of Gas DG 11-192.

2/ The beginning balance is the sum of the actual April 30, 2011 balance $4,200,751 less the May 2011 Billings of $3,570,466, plus reverse of prior month unbilled $3,105,012.

3/ The 5/1/11 - 10/31/11 costs are per Schedule 1, page 1, of the Summer 2011 Reconciliation filed on January 31, 2012 in DG 11-046.

4/ The 5/1/11 - 10/31/11 costs are per Schedule 4, of the Summer 2011Reconciliation filed on January 31, 2012 in DG 11-046.

5/ The 5/1/11 - 10/31/11 costs are per Schedule 1, page 3, of the Summer 2011 Reconciliation filed on January 31, 2012 in DG 11-046.

6/ The 5/1/11 - 10/31/11 costs are per Schedule 5, of the Summer 2011 Reconciliation filed on January 31, 2012 in DG 11-046.

**ENERGY NORTH NATURAL GAS, INC**

**WINTER 2011-2012 COST OF GAS RESULTS**
**DG 11-192**
**SUMMARY OF DEMAND CHARGES FOR PERIOD**
**NOVEMBER 2011 THROUGH APRIL 2012**

| | Filing (a) | 1/ Actual May 11 - Oct 11 (b) | Actual Nov 11 - Apr 12 ( c) | Actual Total Peak Demand (d)=(b)+(c ) | Difference (e)=(d)-(a) |
|---|---|---|---|---|---|
| **Supplies:** | | | | | |
| BP/Nexen | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| ICE | | | | | |
| Subtotal Supply Demand Charges | $6,404 | $0 | $11,147 | $11,147 | $4,743 |
| **Pipelines:** | | | | | |
| Iroquois Gas Trans | $160,191 | $0 | $134,544 | $134,544 | ($25,647) |
| TGP NET 33371 | 259,015 | - | 149,172 | 149,172 | ($109,843) |
| TGP FTA Z5-Z6 2302 | 202,161 | - | 115,760 | 115,760 | ($86,401) |
| TGP FTA Z0 - Z6 8587 | 4,249,377 | - | 2,602,387 | 2,602,387 | ($1,646,990) |
| TGP Dracut FTA Z6 - Z6 42076 | 893,304 | - | 500,563 | 500,563 | ($392,741) |
| TGP (Concord Lateral) Z6-Z6 | 4,089,120 | 1,790,646 | 2,141,433 | 3,932,079 | ($157,041) |
| Portland Natual Gas Pipeline | 241,474 | - | 177,081 | 177,081 | ($64,393) |
| ANE (Uniongas and TransCanada) | 350,302 | - | 357,957 | 357,957 | $7,655 |
| TGP FTA 632 | 2,133,117 | 778,427 | 659,227 | 1,437,655 | ($695,462) |
| TGP FTA 11234 | 1,231,606 | 478,177 | 401,589 | 879,766 | ($351,840) |
| National Fuel | 245,959 | 104,360 | 104,655 | 209,015 | ($36,944) |
| Subtotal Pipeline Demand Charges | $14,055,626 | $3,151,610 | $7,344,370 | $10,495,980 | ($3,559,646) |
| **Peaking Supply** | | | | | |
| Granite Ridge | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| NJR / BG Energy | | | | | |
| DOMAC | | | | | |
| Repsol | | | | | |
| JP Morgan | | | | | |
| Subtotal Peaking Supply | $520,367 | ($475,061) | $554,283 | $79,223 | ($441,145) |
| **Propane** | | | | | |
| Energy North Propane | $0 | $0 | $0 | $0 | $0 |
| **Storage:** | | | | | |
| Demand & Capacity Charges | $1,567,467 | $743,679 | $534,334 | $1,278,013 | ($289,454) |
| **Other:** | | | | | |
| Capacity Managed | ($3,232,529) | (112,664) | ($1,118,790) | ($1,231,454) | $2,001,075 |
| Pipeline Refunds | $0 | $0 | ($879,582) | ($879,582) | ($879,582) |
| **Total Demand Charges (Forward to Page 4)** | $12,917,335 | $3,307,565 | $6,445,762 | $9,753,327 | ($3,164,008) |

1/ Actual Peak Demand costs as filed in Schedule 2B of the Summer 2011 Cost of Gas Reconciliation, DG 11-046 filed January 31, 2012.

**ENERGY NORTH NATURAL GAS, INC**

**WINTER 2011-2012 COST OF GAS RESULTS**
**DG 11-192**
**SUMMARY OF COMMODITY COSTS FOR PERIOD**
**NOVEMBER 2011 THROUGH APRIL 2012**

| | Filing | Average Cost per Therm | Actual | Average Cost per Therm | Difference | |
|---|---|---|---|---|---|---|
| **Demand Charges (Brought from Page 3):** | **$12,917,335** | | **$9,753,327** | | **($3,164,008)** | |
| **TGP Gulf Commodity** | | | | | | |
| Therms | [redacted] | | [redacted] | | [redacted] | |
| Cost | [redacted] | | [redacted] | | [redacted] | |
| **Dracut Commodity** | | | | | | |
| Therms | [redacted] | | [redacted] | | [redacted] | |
| Cost | [redacted] | | [redacted] | | [redacted] | |
| **PNGTS Comodity** | | | | | | |
| Therms | [redacted] | | [redacted] | | [redacted] | |
| Cost | [redacted] | | [redacted] | | [redacted] | |
| **TGP/Iroquois Commodity** | | | | | | |
| Therms | [redacted] | | [redacted] | | [redacted] | |
| Cost | [redacted] | | [redacted] | | [redacted] | |
| **TGP/Niagara Commodity** | | | | | | |
| Therms | [redacted] | | [redacted] | | [redacted] | |
| Cost | [redacted] | | [redacted] | | [redacted] | |
| **City Gate Delivered Supply** | | | | | | |
| Therms | [redacted] | | [redacted] | | [redacted] | |
| Cost | [redacted] | | [redacted] | | [redacted] | |
| **Storage Gas - Commodity Withdrawn** | | | | | | |
| Therms | [redacted] | | [redacted] | | [redacted] | |
| Cost | [redacted] | | [redacted] | | [redacted] | |
| **Propane P/S Plant Commodity** | | | | | | |
| Therms | [redacted] | | [redacted] | | [redacted] | |
| Cost | [redacted] | | [redacted] | | [redacted] | |
| **Propane Tank Farm Commodity** | | | | | | |
| Therms | [redacted] | | [redacted] | | [redacted] | |
| Cost | [redacted] | | [redacted] | | [redacted] | |
| **LNG P/S Plant Commodity** | | | | | | |
| Therms | [redacted] | | [redacted] | | [redacted] | |
| Cost | [redacted] | | [redacted] | | [redacted] | |
| **Hedging (Gains) Losses** | [redacted] | | [redacted] | | [redacted] | |
| **Other- Cashout, Broker Penalty, Canadian Managed, Non-Firm costs** | | | | | | |
| Therms | [redacted] | | [redacted] | | [redacted] | |
| Cost | [redacted] | | [redacted] | | [redacted] | |
| Prior period Adj | [redacted] | | [redacted] | | [redacted] | |
| Subtotal: | | | | | | |
| Volumes (net of fuel retention) | 85,279,058 | | 68,109,980 | | (17,169,078) | |
| Cost | $ 46,765,731 | 0.5484 | $ 35,119,541 | 0.5156 | $ (11,646,190) | (0.0328) |
| Total Demand and Commodity Costs | $ 59,683,066 | | $ 44,872,868 | | $ (14,810,198) | |
| Demand (therms): | 85,279,058 | | 68,109,980 | | (17,169,078) | |
| Firm Gas Sales | 82,632,661 | | 65,771,915 | | (16,860,746) | |
| Lost Gas (Unaccounted For) | 1,652,632 | | 2,104,598 | | 451,966 | |
| Unbilled Therms | 14,672 | | (604,340) | | (619,012) | |
| Fuel Retention | - | | - | | - | |
| Company Use | 979,095 | | 837,807 | | (141,288) | |
| Total Demand | 85,279,060 | | 68,109,980 | | (17,169,080) | |

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**ENERGY NORTH NATURAL GAS, INC**

**WINTER 2011-2012 COST OF GAS RESULTS**
**DG 11-192**

| **Weather Variance - Volume Impact** | **(A) Actual Volume** | **(B) Normal Volume** | **(C) Actual Rate** | **(A-B)*C Difference** |
|---|---|---|---|---|
| TGP Gulf | [redacted] | | | |
| TGP/Iroquios | | | | |
| TGP/Niagra | | | | |
| PNGTS | | | | |
| Dracut | | | | |
| City Gate Delivered Supply | | | | |
| DOMAC | | | | |
| Storage gas - commodity withdrawn | | | | |
| Propane | | | | |
| LNG | | | | |
| Total Volume Weather Varaince | 68,109,980 | 77,928,952 | | $ (3,447,242) |

| **Demand Variance - Commodity Costs** | **(A) Forecast Volume** | **(B) Actual Volume** | **(C) Forecast Rate** | **(B-A)*C Difference** |
|---|---|---|---|---|
| TGP Gulf | [redacted] | | | |
| TGP/Iroquios | | | | |
| TGP/Niagra | | | | |
| PNGTS Comodity | | | | |
| City Gate Delivered Supply | | | | |
| Dracut | | | | |
| Storage Gas - Commodity Withdrawn | | | | |
| Propane P/S Plant Commodity | | | | |
| LNG P/S Plant Commodity | | | | |
| Total Demand Variance (Less: Fuel Retention) | 85,279,058 | 68,109,980 | | $ (11,190,391) |

**Demand Variance Net of Weather Variance** (7,743,150)

| **Rate Variance - Commodity Costs** | **(A) Actual Volume** | **(B) Forecast Rate** | **(C) Actual Rate** | **(C-B)*A Difference** |
|---|---|---|---|---|
| TGP Gulf | [redacted] | | | |
| TGP/Iroquios | | | | |
| TGP/Niagra | | | | |
| PNGTS Comodity | | | | |
| Dracut | | | | |
| DOMAC | | | | |
| Storage Gas - Commodity Withdrawn | | | | |
| Propane P/S Plant Commodity | | | | |
| LNG P/S Plant Commodity | | | | |
| Total Commodity Cost Rate Variance | 68,109,980 | | | $ (5,147,155) |

| | |
|---|---|
| Demand Charge Variance (from page 3) | (3,164,008) |
| Other Rate Variance (from page 4) | |
| Hedging (Gains)/Losses | 4,710,205 |
| Cashout, Broker Penalty, Canadian Managed, Prior Period Adjustments | (18,848) |
| Total Rate Variance | $ (3,619,807) |
| Due to Weather Variance | (3,447,242) |
| Due to Demand Variance (from above) | (7,743,150) |
| Total Gas Cost Variance | $ (14,810,198) |

**ENERGY NORTH NATURAL GAS, INC**

**WINTER 2011-2012 COST OF GAS RESULTS**
**DG 11-192**

| | FILING | ACTUAL |
|---|---|---|
| Cost of Propane | $ - | $ 19,541 |
| Cost of LNG | 381,653 | 244,922 |
| Total Costs | 381,653 | 264,463 |
| Percentage of Supplies Used For Pressure Support Purposes | 9.9% | 9.9% |
| Cost of Supplies Used For Pressure Support Purposes | 37,784 | 26,182 |
| | | |
| Firm Therms Sold | 82,647,332 | 65,771,915 |
| Firm Therms Transported | 36,930,101 | 34,162,155 |
| Total Therms | 119,577,433 | 99,934,070 |
| | | |
| Actual Liquid Cost/Therm | 0.0003 | 0.0003 |
| | | |
| Firm Therms Transported | 36,930,101 | 34,162,155 |
| | | |
| Liquid Costs Allocated to Transported Therms | 11,669 | 8,950 |
| Prior (Over) or under Collection | (10,838) | (10,838) |
| Total | 831 | (1,888) |
| | | |
| Costs Recovered: | | |
| | | |
| Therms Transported | 36,930,101 | 34,162,155 |
| Recovery Rate | 0.0000 | - |
| Costs Recovered | 0 | - |
| | | |
| (Over) / Under Collection For Period | 831 | (1,888) |

**ENERGY NORTH NATURAL GAS, INC**

**NOVEMBER 2011 THROUGH APRIL 2012**
**PEAK DEMAND AND COMMODITY**
**SCHEDULE 1**
**ACCOUNT 175.20**

| | FOR THE MONTH OF: | Nov-11 | Dec-11 | Jan-12 | Feb-12 | Mar-12 | Apr-12 | May-12 | Total |
|---|---|---|---|---|---|---|---|---|---|
| | DAYS IN MONTH | 30 | 31 | 31 | 29 | 31 | 30 | | |
| 1 | BEGINNING BALANCE | $ 5,625,298 | $ 4,412,942 | $ 4,356,536 | $ 3,405,366 | $ 3,058,426 | $ 2,900,816 | $ 2,076,323 | **$ 5,625,298** |
| 2 | | | | | | | | | |
| 3 | Add: Actual Costs | 4,969,709 | 8,992,035 | 10,290,854 | 8,044,444 | 5,848,215 | 3,420,047 | | **41,565,303** |
| 4 | | | | | | | | | |
| 5 | Add. FPO Admin Costs | - | - | - | - | - | - | | - |
| 6 | Add: MISC OH | 1,723 | 1,723 | 1,723 | 1,723 | 1,723 | 1,723 | | **10,337** |
| 7 | Add: Production and Storage | 330,071 | 330,071 | 330,071 | 330,071 | 330,071 | 330,071 | | **1,980,428** |
| 8 | Add: Fuel Financing | 7,461 | 20,451 | 13,012 | 17,177 | 32,756 | 16,357 | | **107,214** |
| 9 | Reverse Fuel Finance Estimate | | - | | | - | | | - |
| 10 | Add new Fuel Finance Estimate | | - | | | - | | | - |
| 11 | | | | | | | | | |
| 12 | Less: CUSTOMER BILLINGS | (1,561,988) | (7,054,008) | (10,548,793) | (10,446,693) | (9,300,630) | (5,703,419) | (2,824,803) | **(47,440,335)** |
| 13 | Estimated Unbilled | (4,911,161) | (7,215,127) | (8,224,110) | (6,469,273) | (3,531,311) | (2,355,050) | | **(32,706,032)** |
| 14 | Reverse Prior Month Unbilled | | 4,911,161 | 7,215,127 | 8,224,110 | 6,469,273 | 3,531,311 | 2,355,050 | **32,706,032** |
| 15 | Sub-Total Accrued Customer Billings | (6,473,149) | (9,357,975) | (11,557,775) | (8,691,857) | (6,362,668) | (4,527,157) | (469,754) | **(47,440,335)** |
| 16 | | | | | | | | | |
| 17 | Less: REFUND | - | - | - | - | - | - | | - |
| 18 | | | | | | | | | |
| 19 | Less: Broker Revenues | (59,962) | (52,719) | (37,893) | (51,607) | (10,518) | (38,091) | - | **(250,791)** |
| 20 | | | | | | | | | |
| 21 | NON FIRM MARGIN AND CREDITS | (1,598) | (2,077) | (1,860) | (5,227) | (5,402) | (34,082) | - | **(50,245)** |
| 22 | | | | | | | | | |
| 23 | ENDING BALANCE PRE INTEREST | **$ 4,399,553** | **$ 4,344,450** | **$ 3,394,668** | **$ 3,050,091** | **$ 2,892,603** | **$ 2,069,684** | **$ 1,606,569** | **$ 1,547,209** |
| 24 | | | | | | | | | |
| 25 | MONTH'S AVERAGE BALANCE | 5,012,425 | 4,378,696 | 3,875,602 | 3,227,729 | 2,975,514 | 2,485,250 | | |
| 26 | | | | | | | | | |
| 27 | INTEREST RATE | 3.25% | 3.25% | 3.25% | 3.25% | 3.25% | 3.25% | | |
| 28 | | | | | | | | | |
| 29 | INTEREST APPLIED | 13,389 | 12,086 | 10,698 | 8,335 | 8,213 | 6,639 | | **59,360** |
| 30 | | | | | | | | | |
| 31 | ENDING BALANCE | **$ 4,412,942** | **$ 4,356,535.92** | **$ 3,405,366** | **$ 3,058,426** | **$ 2,900,816** | **$ 2,076,323** | **$ 1,606,569** | **$ 1,606,569** |

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**ENERGY NORTH NATURAL GAS, INC**

**NOVEMBER 2011 THROUGH APRIL 2012**
**OFF PEAK DEMAND AND COMMODITY**
**SCHEDULE 1**
**ACCOUNT 175.40**

| | FOR THE MONTH OF: | Nov-11 | Dec-11 | Jan-12 | Feb-12 | Mar-12 | Apr-12 | May-12 | Total |
|---|---|---|---|---|---|---|---|---|---|
| | DAYS IN MONTH | 30 | 31 | 31 | 29 | 31 | 30 | | |
| 1 | BEGINNING BALANCE | $ 680,336 | $ (408,621) | $ (409,749) | $ (410,880) | $ (411,941) | $ (1,162,743) | $ (1,165,849) | **680,336** |
| 2 | | | | | | | | | |
| 3 | Add:ACTUAL COST | - | - | - | - | (748,632) | - | | **$ (748,632)** |
| 4 | | | | | | | | | |
| 5 | Add: MISC OH & PROD and STOR | - | - | - | - | - | - | | **-** |
| 6 | | | | | | | | | |
| 7 | Less: CUSTOMER BILLINGS | (2,970,287) | - | - | - | - | - | - | **(2,970,287)** |
| 8 | Estimated Unbilled | | - | - | - | - | - | | **-** |
| 9 | Reverse Prior Month Unbilled | 1,880,968 | - | - | - | - | - | - | **1,880,968** |
| 10 | Sub-Total Accrued Customer Billings | (1,089,319) | - | - | - | - | - | - | (1,089,319) |
| 11 | | | | | | | | | |
| 12 | Add: ADJUSTMENTS | - | - | - | - | - | - | - | - |
| 13 | | | | | | | | | |
| 14 | ENDING BALANCE PRE INTEREST | **$ (408,983)** | **$ (408,621)** | **$ (409,749)** | **$ (410,880)** | **$ (1,160,573)** | **$ (1,162,743)** | **$ (1,165,849)** | **$ (1,157,615)** |
| 15 | | | | | | | | | |
| 16 | MONTH'S AVERAGE BALANCE | 135,676 | (408,621) | (409,749) | (410,880) | (786,257) | (1,162,743) | | |
| 17 | | | | | | | | | |
| 18 | INTEREST RATE | 3.25% | 3.25% | 3.25% | 3.25% | 3.25% | 3.25% | | |
| 19 | | | | | | | | | |
| 20 | INTEREST APPLIED | 362 | (1,128) | (1,131) | (1,061) | (2,170) | (3,106) | | **(8,234)** |
| 21 | | | | | | | | | |
| 22 | ENDING BALANCE | **$ (408,621)** | **$ (409,749)** | **$ (410,880)** | **$ (411,941)** | **$ (1,162,743)** | **$ (1,165,849)** | **$ (1,165,849)** | **$ (1,165,849)** |

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**ENERGY NORTH NATURAL GAS, INC**

**MAY 2011 THROUGH OCTOBER 2011**
**PEAK BAD DEBT**
**SCHEDULE 1A**
**ACCOUNTS 175.52 and 175.54**

| | FOR THE MONTH OF:<br>DAYS IN MONTH | May-11<br>31 | Jun-11<br>30 | Jul-11<br>31 | Aug-11<br>31 | Sep-11<br>30 | Oct-11<br>31 | | Total |
|---|---|---|---|---|---|---|---|---|---|
| 1 | BEGINNING BALANCE | $ 60,123 | $ 142,670 | $ 162,766 | $ 177,963 | $ 203,556 | $ 219,853 | | **60,123** |
| 2 | | | | | | | | | |
| 3 | Add: COST ALLOW | 68,670 | 61,711 | 45,459 | 61,250 | 53,929 | 90,434 | | **$ 381,454** |
| 4 | | | | | | | | | |
| 5 | Adjustment | - | - | - | - | - | - | | - |
| 6 | | | | | | | | | |
| 7 | Less: CUSTOMER BILLINGS | (28,212) | (58,324) | (42,110) | (34,219) | (36,398) | (46,190) | | **(245,454)** |
| 8 | Estimated Unbilled | (32,928) | (16,626) | (5,249) | (7,212) | (9,012) | (45,481) | | **(116,508)** |
| 9 | Reverse Prior Month Unbilled | 74,739 | 32,928 | 16,626 | 5,249 | 7,212 | 9,012 | | **145,766** |
| 10 | Sub-Total Accrued Customer Billings | 13,598 | (42,022) | (30,733) | (36,183) | (38,197) | (82,659) | | (216,196) |
| 11 | | | | | | | | | |
| 12 | ENDING BALANCE PRE INTEREST | **$ 142,391** | **$ 162,359** | **$ 177,493** | **$ 203,030** | **$ 219,288** | **$ 227,628** | | **$ 225,381** |
| 13 | | | | | | | | | |
| 14 | MONTH'S AVERAGE BALANCE | 101,257 | 152,515 | 170,130 | 190,497 | 211,422 | 223,741 | | |
| 15 | | | | | | | | | |
| 16 | INTEREST RATE | 3.25% | 3.25% | 3.25% | 3.25% | 3.25% | 3.25% | | |
| 17 | | | | | | | | | |
| 18 | INTEREST APPLIED | 279 | 407 | 470 | 526 | 565 | 618 | | **$ 2,865** |
| 19 | | | | | | | | | |
| 20 | ENDING BALANCE | **$ 142,670** | **$ 162,766** | **$ 177,963** | **$ 203,556** | **$ 219,853** | **$ 228,246** | | **$ 228,246** |

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**ENERGY NORTH NATURAL GAS, INC**

**NOVEMBER 2011 THROUGH APRIL 2012**
**PEAK BAD DEBT**
**SCHEDULE 1A**
**ACCOUNTS 175.52 and 175.54**

| | FOR THE MONTH OF: | Nov-11 | Dec-11 | Jan-12 | Feb-12 | Mar-12 | Apr-12 | May-12 | Total |
|---|---|---|---|---|---|---|---|---|---|
| | DAYS IN MONTH | 30 | 31 | 31 | 29 | 31 | 30 | | |
| 1 | BEGINNING BALANCE | $ 228,246 | $ 186,855 | $ 185,908 | $ 156,234 | $ 142,525 | $ 138,176 | $ 124,588 | **228,246** |
| 2 | | | | | | | | | |
| 3 | Add: COST ALLOW | 139,872 | 240,508 | 273,013 | 216,718 | 161,759 | 100,283 | | **$ 1,132,153** |
| 4 | | | | | | | | | |
| 5 | Adjustment | - | - | - | - | - | - | - | - |
| 6 | | | | | | | | | |
| 7 | Less: CUSTOMER BILLINGS | (109,125) | (172,971) | (271,959) | (274,134) | (246,709) | (148,752) | (71,543) | **(1,295,194)** |
| 8 | Estimated Unbilled | (118,173) | (187,171) | (218,370) | (175,049) | (94,835) | (60,303) | | **(853,900)** |
| 9 | Reverse Prior Month Unbilled | 45,481 | 118,173 | 187,171 | 218,370 | 175,049 | 94,835 | 60,303 | **899,381** |
| 10 | Sub-Total Accrued Customer Billings | (181,817) | (241,969) | (303,159) | (230,813) | (166,495) | (114,220) | (11,241) | (1,249,713) |
| 11 | | | | | | | | | |
| 12 | ENDING BALANCE PRE INTEREST | **$ 186,301** | **$ 185,394** | **$ 155,762** | **$ 142,140** | **$ 137,789** | **$ 124,238** | **$ 113,348** | **$ 110,686** |
| 13 | | | | | | | | | |
| 14 | MONTH'S AVERAGE BALANCE | 207,274 | 186,125 | 170,835 | 149,187 | 140,157 | 131,207 | | |
| 15 | | | | | | | | | |
| 16 | INTEREST RATE | 3.25% | 3.25% | 3.25% | 3.25% | 3.25% | 3.25% | | |
| 17 | | | | | | | | | |
| 18 | INTEREST APPLIED | 554 | 514 | 472 | 385 | 387 | 350 | | **$ 2,662** |
| 19 | | | | | | | | | |
| 20 | ENDING BALANCE | **$ 186,855** | **$ 185,908** | **$ 156,234** | **$ 142,525** | **$ 138,176** | **$ 124,588** | **$ 113,348** | **$ 113,348** |

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**ENERGY NORTH NATURAL GAS, INC**

**NOVEMBER 2011 THROUGH APRIL 2012**
**GAS COSTS BY SOURCE**
**SCHEDULE 2A**

| | FOR THE MONTH OF: | Nov-11 | Dec-11 | Jan-12 | Feb-12 | Mar-12 | Apr-12 | Total |
|---|---|---|---|---|---|---|---|---|
| 1 | **DEMAND** | | | | | | | |
| 2 | | | | | | | | |
| 3 | ALBERTA NORTHEAST | [redacted] | | | | | | |
| 4 | BP/NORTHEAST GAS MARKETS | | | | | | | |
| 5 | CANADIAN CAPACITY MANAGED | | | | | | | |
| 6 | TOTAL CANADIAN DEMAND | $ (170,917.40) | $ (171,937.08) | $ (175,089.68) | $ (204,311.82) | $ (187,064.88) | $ (192,669.54) | **$ (1,101,990.40)** |
| 7 | | | | | | | | |
| 8 | PEAKING SUPPLY | 9,631.02 | 9,130.42 | 9,130.42 | 9,130.42 | 9,130.42 | 9,130.42 | **55,283.12** |
| 9 | | | | | | | | |
| 10 | TRANSPORT CAPACITY | 1,239,958.44 | 1,201,003.95 | 1,206,062.34 | 1,208,296.49 | 1,202,380.37 | 1,233,141.43 | **7,290,843.02** |
| 11 | CAPACITY RELEASE ADJUSTMENT | 1,007.50 | 2,077.00 | 1,860.00 | 1,542.75 | 1,472.50 | 32,788.75 | **40,748.50** |
| 12 | TOTAL TRANSPORT | $ 1,240,965.94 | $ 1,203,080.95 | $ 1,207,922.34 | $ 1,209,839.24 | $ 1,203,852.87 | $ 1,265,930.18 | **$ 7,331,591.52** |
| 13 | | | | | | | | |
| 14 | STORAGE FIXED COSTS | 36,220.00 | 93,532.33 | 102,729.95 | 100,720.81 | 105,483.13 | 95,647.34 | **534,333.56** |
| 15 | | | | | | | | |
| 16 | LNG | - | 124,750.00 | 124,750.00 | 124,750.00 | 124,750.00 | - | **499,000.00** |
| 17 | | | | | | | | |
| 18 | PROPANE | - | - | - | - | - | - | **-** |
| 19 | | | | | | | | |
| 20 | PIPELINE REFUNDS | - | (288,376.35) | - | - | (1,051,461.38) | (288,376.34) | **(1,628,214.07)** |
| 21 | | | | | | | | |
| 22 | OTHER | 543.13 | 1,086.26 | 1,086.26 | 1,303.50 | 1,803.50 | 1,303.50 | **7,126.15** |
| 23 | | | | | | | | |
| 24 | | | | | | | | |
| 25 | | | | | | | | |
| 26 | **TOTAL DEMAND** | **$ 1,116,442.69** | **$ 971,266.53** | **$ 1,270,529.29** | **$ 1,241,432.15** | **$ 206,493.66** | **$ 890,965.56** | **$ 5,697,129.88** |
| 27 | | | | | | | | |
| 28 | **COMMODITY** | | | | | | | |
| 29 | | | | | | | | |
| 30 | ALBERTA NORTHEAST / BP | [redacted] | | | | | | |
| 31 | ALBERTA NORTHEAST / Emera | | | | | | | |
| 32 | SHELL CANADA | | | | | | | |
| 33 | TOTAL CANADIAN COMMODITY | **$ 797,711.16** | **$ 841,013.66** | **$ 771,324.51** | **$ 707,836.61** | **$ 605,583.52** | **$ 44,716.17** | **$ 3,768,185.63** |
| 34 | | | | | | | | |
| 35 | PIPELINE TRANSPORT | [redacted] | | | | | | |
| 36 | DRACUT SUPPLY | | | | | | | |
| 37 | PNGTS | | | | | | | |
| 38 | | | | | | | | |
| 39 | GAS SUPPLY | [redacted] | | | | | | |
| 40 | | | | | | | | |
| 41 | STORAGE | [redacted] | | | | | | |
| 42 | | | | | | | | |
| 43 | LNG | [redacted] | | | | | | |
| 44 | | | | | | | | |
| 45 | PROPANE | [redacted] | | | | | | |
| 46 | | | | | | | | |
| 47 | **OTHER COST ADJUSTMENTS** | | | | | | | |
| 48 | CANDIAN CAPACITY MANAGED | [redacted] | | | | | | |
| 49 | SUPPLIER CASHOUT | | | | | | | |
| 50 | NET OTHER COST ADJUSTMENTS | | | | | | | |
| 51 | | | | | | | | |
| 52 | **SUBTOTAL COMMODITY COST** | **$ 3,905,345.61** | **$ 8,020,768.17** | **$ 9,020,324.75** | **$ 6,846,403.18** | **$ 4,908,034.51** | **$ 2,534,588.43** | **$ 35,235,464.65** |
| 53 | | | | | | | | |
| 54 | OFF SYSTEM SALES COST | [redacted] | | | | | | |
| 55 | OFF SYSTEM SALES COST - PPA | | | | | | | |
| 56 | NON-FIRM COST | | | | | | | |
| 57 | | | | | | | | |
| 58 | **TOTAL COMMODITY COST** | **$ 3,853,266.01** | **$ 8,020,768.17** | **$ 9,020,324.75** | **$ 6,803,011.93** | **$ 4,893,089.04** | **$ 2,529,081.38** | **$ 35,119,541.28** |
| 59 | | | | | | | | |

**ENERGY NORTH NATURAL GAS, INC**

**NOVEMBER 2011 THROUGH APRIL 2012**
**GAS COSTS SUMMARY**
**SCHEDULE 2A**

| | FOR THE MONTH OF: | Nov-11 | Dec-11 | Jan-12 | Feb-12 | Mar-12 | Apr-12 | Total |
|---|---|---|---|---|---|---|---|---|
| 67 | | | | | | | | |
| 68 | **Total Peak Demand** | **$ 1,116,442.69** | **$ 971,266.53** | **$ 1,270,529.29** | **$ 1,241,432.15** | **$ 955,125.81** | **$ 890,965.56** | **$ 6,445,762.03** |
| 69 | **Off-Peak Demand** | - | - | - | - | **(748,632.15)** | - | **(748,632.15)** |
| 70 | **Total Demand** | **$ 1,116,442.69** | **$ 971,266.53** | **$ 1,270,529.29** | **$ 1,241,432.15** | **$ 206,493.66** | **$ 890,965.56** | **$ 5,697,129.88** |
| 71 | | | | | | | | |
| 72 | **Total Peak Commodity** | **$ 3,853,266.01** | **$ 8,020,768.17** | **$ 9,020,324.75** | **$ 6,803,011.93** | **$ 4,893,089.04** | **$ 2,529,081.38** | **$ 35,119,541.28** |
| 73 | **Off-Peak Commodity** | - | - | - | - | - | - | - |
| 74 | **Total Commodity** | **$ 3,853,266.01** | **$ 8,020,768.17** | **$ 9,020,324.75** | **$ 6,803,011.93** | **$ 4,893,089.04** | **$ 2,529,081.38** | **$ 35,119,541.28** |
| 75 | | | | | | | | |
| 76 | **Firm Sendout Costs** | **$ 4,969,708.70** | **$ 8,992,034.70** | **$ 10,290,854.04** | **$ 8,044,444.08** | **$ 5,099,582.70** | **$ 3,420,046.94** | **$ 40,816,671.16** |

**ENERGY NORTH NATURAL GAS, INC**

**NOVEMBER 2011 THROUGH APRIL 2012**
**DETAIL GAS COSTS BY SOURCE**
**SCHEDULE 2B**

| | FOR THE MONTH OF: | | Nov-11 | Dec-11 | Jan-12 | Feb-12 | Mar-12 | Apr-12 | Total |
|---|---|---|---|---|---|---|---|---|---|
| 1 | **DEMAND** | | | | | | | | |
| 2 | **Supply** | | | | | | | | |
| 3 | Alberta Northeast | | | | | | | | |
| 4 | Northeast Gas Markets/BP | | | | | | | | |
| 5 | **Subtotal Canadian Supply** | | **$ 1,336.46** | **$ 5,002.61** | **$ 2,835.74** | **$ 2,684.93** | **$ 2,785.21** | **$ 2,154.31** | **$ 16,799.26** |
| 6 | **Peaking Suppy** | | | | | | | | |
| 7 | Repsol | | | | | | | | |
| 8 | Granite Ridge | | | | | | | | |
| 9 | NRJ/BG Energy | | | | | | | | |
| 10 | JP Morgan | | | | | | | | |
| 11 | **Subtotal Peaking Supply** | | **$ 9,631.02** | **$ 9,130.42** | **$ 9,130.42** | **$ 9,130.42** | **$ 9,130.42** | **$ 9,130.42** | **$ 55,283.12** |
| 12 | | | | | | | | | |
| 13 | **Transport Capacity** | | | | | | | | |
| 14 | Iroquois 470-01-RTS | | $ 22,987.18 | $ 22,357.56 | $ 22,819.74 | $ 22,166.25 | $ 22,166.25 | $ 22,047.51 | **$ 134,544.49** |
| 15 | National Fuel N02358 | | 17,935.67 | 17,327.38 | 17,290.18 | 17,186.04 | 17,185.81 | 17,729.86 | **104,654.94** |
| 16 | PNGTS FT-1999-001 | | 39,238.10 | 22,070.36 | 14,238.24 | 22,196.48 | 18,288.21 | 51,732.00 | **167,763.39** |
| 17 | Transcanada | | 47,383.67 | 44,790.93 | 48,964.93 | 47,369.12 | 48,856.09 | 48,229.06 | **285,593.80** |
| 18 | TGP 632 FTA | | 138,248.07 | 81,581.62 | 109,956.93 | 109,210.56 | 108,675.36 | 108,089.58 | **655,762.12** |
| 19 | TGP 2302 FTA Zone 5-6 | | 12,278.43 | 26,600.94 | 19,365.28 | 19,246.24 | 19,119.78 | 19,149.53 | **115,760.20** |
| 20 | TGP 8587 FTA | | 431,650.54 | 442,541.48 | 434,769.04 | 431,906.36 | 431,906.61 | 429,613.08 | **2,602,387.11** |
| 21 | TGP 11234 FTA | | 78,186.23 | 52,917.93 | 65,301.92 | 64,988.09 | 64,987.51 | 64,707.66 | **391,089.34** |
| 22 | TGP 33371 NET | | 15,832.50 | 34,040.70 | 25,439.87 | 26,022.39 | 23,285.96 | 24,550.68 | **149,172.10** |
| 23 | TGP 72694 NET | | 357,469.41 | 357,226.01 | 356,495.81 | 356,860.91 | 356,800.06 | 356,581.00 | **2,141,433.20** |
| 24 | TGP 42076 FTA | | 69,024.39 | 89,783.93 | 81,572.81 | 81,050.16 | 81,050.16 | 80,615.44 | **483,096.89** |
| 25 | Union Gas | | 9,724.25 | 9,765.11 | 9,847.59 | 10,093.89 | 10,058.57 | 10,096.03 | **59,585.44** |
| 26 | **Subtotal Transport Capacity** | | **$ 1,239,958.44** | **$ 1,201,003.95** | **$ 1,206,062.34** | **$ 1,208,296.49** | **$ 1,202,380.37** | **$ 1,233,141.43** | **$ 7,290,843.02** |
| 27 | | | | | | | | | |
| 28 | **Storage Fixed** | | | | | | | | |
| 29 | Sempra | | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** |
| 30 | Dominion 300076-Storage | | 2,676.08 | 2,758.98 | 2,730.42 | 2,716.08 | 2,944.99 | 2,476.28 | **16,302.83** |
| 31 | NFG Deliverability FSS 2357 | | 36,682.63 | 35,345.52 | 35,515.03 | 35,686.72 | 35,649.40 | 33,765.26 | **212,644.56** |
| 32 | Tenn Reservation FSMA 523 | | (11,883.10) | 46,683.44 | 55,740.11 | 53,573.62 | 58,144.35 | 50,661.41 | **252,919.83** |
| 33 | Honeoye Storage SS-NY | | 8,744.39 | 8,744.39 | 8,744.39 | 8,744.39 | 8,744.39 | 8,744.39 | **52,466.34** |
| 34 | **Subtotal Storage** | | **$ 36,220.00** | **$ 93,532.33** | **$ 102,729.95** | **$ 100,720.81** | **$ 105,483.13** | **$ 95,647.34** | **$ 534,333.56** |
| 35 | | | | | | | | | |
| 36 | **LNG / DISTRIGAS** | | | | | | | | |
| 37 | **LNG/ DISTRIGAS FLS160** | | | | | | | | |
| 38 | **Transgas Trucking** | | | | | | | | |
| 39 | **Subtotal Distrigas** | | $ - | $ 124,750.00 | $ 124,750.00 | $ 124,750.00 | $ 124,750.00 | $ - | **$ 499,000.00** |
| 40 | | | | | | | | | |
| 41 | **Propane** | | | | | | | | |
| 42 | **En Propane** | | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** |
| 43 | | | | | | | | | |
| 44 | **Intercontinental Exchange** | | $ 543 | $ 1,086 | $ 1,086 | $ 1,304 | $ 1,804 | $ 1,304 | **7,126.15** |
| 45 | | | | | | | | | |
| 46 | **Capacity Managed - Canadian** | | | | | | | | |
| 47 | | | | | | | | | |
| 48 | **PNGTS Refund per RP02-13** | | | | | | | | |
| 49 | **TGP Pipeline Refund** | PK | $ - | $ (288,376.35) | $ - | $ - | $ (302,829.23) | $ (288,376.34) | **(879,581.92)** |
| 50 | **TGP Pipeline Refund** | OP | $ - | $ - | $ - | $ - | $ (748,632.15) | $ - | **(748,632.15)** |
| 51 | **Demand Subtotal** | | **$ 1,115,435.19** | **$ 969,189.53** | **$ 1,268,669.29** | **$ 1,239,889.40** | **$ 205,021.16** | **$ 858,176.81** | **$ 5,656,381.38** |
| 52 | | | | | | | | | |
| 53 | **Capacity Release Adjustment** | | | | | | | | |
| 54 | ALBERTA NORTHEAST | | | | | | | | |
| 55 | TGP - FT-A 95346 | | | | | | | | |
| 56 | TGP - FT-A 42076 | | | | | | | | |
| 57 | TGP - FT-A 2302 | | | | | | | | |
| 58 | PNGTS - FT | | | | | | | | |
| 59 | **Total Capacity Release Adjustment** | | | | | | | | |
| 60 | | | | | | | | | |
| 61 | **TOTAL DEMAND** | | **$ 1,116,442.69** | **$ 971,266.53** | **$ 1,270,529.29** | **$ 1,241,432.15** | **$ 206,493.66** | **$ 890,965.56** | **$ 5,697,129.88** |

**ENERGY NORTH NATURAL GAS, INC**

**NOVEMBER 2011 THROUGH APRIL 2012**
**DETAIL GAS COSTS BY SOURCE**
**SCHEDULE 2B**

| | FOR THE MONTH OF: | Nov-11 | Dec-11 | Jan-12 | Feb-12 | Mar-12 | Apr-12 | Total |
|---|---|---|---|---|---|---|---|---|
| 63 | | | | | | | | |
| 64 | **COMMODITY** | | | | | | | |
| 65 | | | | | | | | |
| 66 | **Canadian Supply** | | | | | | | |
| 67 | BP | | | | | | | |
| 68 | ANE Union/Dawn/Iroquois (BG) | | | | | | | |
| 69 | Shell Canada | | | | | | | |
| 70 | **Subtotal Canadian Commodity** | | | | | | | |
| 71 | | | | | | | | |
| 72 | **Pipeline Transport** | | | | | | | |
| 73 | ANE Union/Dawn | | | | | | | |
| 74 | | | | | | | | |
| 75 | Dominion | | | | | | | |
| 76 | El Paso | | | | | | | |
| 77 | Iroquois | | | | | | | |
| 78 | National Fuel | | | | | | | |
| 79 | PNGTS | | | | | | | |
| 80 | **Subtotal TGP Transportation** | | | | | | | |
| 81 | **Total Transportation** | | | | | | | |
| 82 | | | | | | | | |
| 83 | **City Gate Delivery** | | | | | | | |
| 84 | VPEM | | | | | | | |
| 85 | | | | | | | | |
| 86 | **Dracut Supply (Repsol)** | | | | | | | |
| 87 | | | | | | | | |
| 88 | **PNGTS Supply** | | | | | | | |
| 89 | Emera | | | | | | | |
| 90 | Shell | | | | | | | |
| 91 | | | | | | | | |
| 92 | **Subtotal PNGTS** | | | | | | | |
| 93 | | | | | | | | |
| 94 | **Gas Supply** | | | | | | | |
| 95 | Andarko | | | | | | | |
| 96 | J Aron | | | | | | | |
| 97 | BG LNG | | | | | | | |
| 98 | Barclay | | | | | | | |
| 99 | BP Energy | | | | | | | |
| 100 | Chevron | | | | | | | |
| 101 | Cheniere | | | | | | | |
| 102 | Conoco | | | | | | | |
| 103 | EServices | | | | | | | |
| 104 | StatOil | | | | | | | |
| 105 | EnCan | | | | | | | |
| 106 | Gavilon | | | | | | | |
| 107 | JP Morgan | | | | | | | |
| 108 | Hess | | | | | | | |
| 109 | L. Dreyfus | | | | | | | |
| 110 | Macquarie | | | | | | | |
| 111 | Merrill | | | | | | | |
| 112 | NJR Energy | | | | | | | |
| 113 | Repsol | | | | | | | |
| 114 | South Jersey | | | | | | | |
| 115 | Shell US | | | | | | | |
| 116 | Spark | | | | | | | |
| 117 | Tenaska | | | | | | | |
| 118 | Total Gas & Power | | | | | | | |
| 119 | VPEM | | | | | | | |
| 120 | United | | | | | | | |
| 121 | **Total Other TGP Supply** | | | | | | | |
| 122 | | | | | | | | |
| 123 | **Peaking Supply** | | | | | | | |
| 124 | Granite Ridge (formerly AES ) | | | | | | | |
| 125 | | | | | | | | |
| 126 | NYMEX Hedging (Gains) Losses | | | | | | | |
| 127 | | | | | | | | |
| 128 | **STORAGE WITHDRAWALS** | | | | | | | |
| 129 | | | | | | | | |
| 130 | **STORAGE INJECTIONS** | | | | | | | |
| 131 | | | | | | | | |
| 132 | DISTRIGAS (FLS187) | | | | | | | |
| 133 | LNG VAPOR | | | | | | | |
| 134 | LNG BOIL OFF | | | | | | | |
| 135 | **Subtotal LNG** | | | | | | | |
| 136 | **PROPANE** | | | | | | | |
| 137 | Country Gas | | | | | | | |
| 138 | Propane Storage Withdrawal | | | | | | | |
| 139 | Energy North Propane | | | | | | | |
| 140 | **Subtotal Propane** | | | | | | | |
| 141 | | | | | | | | |
| 142 | Broker Cashout | | | | | | | |
| 143 | Other Taxes W. Virginia | | | | | | | |
| 144 | **Subtotal Cashouts** | | | | | | | |
| 145 | | | | | | | | |
| 146 | Capacity Managed - Canadian | | | | | | | |
| 147 | Broker Inventory | | | | | | | |
| 148 | **Subtotal Capacity Managed** | | | | | | | |
| 149 | | | | | | | | |
| 150 | **TOTAL COMMODITY** | | | | | | | |
| 151 | | | | | | | | |
| 152 | Off System Gas Sales Cost | | | | | | | |
| 153 | Off System Sales Costs - PPA | | | | | | | |
| 154 | NON-FIRM COST | | | | | | | |
| 155 | | | | | | | | |
| 156 | **NET COMMODITY COST** | **$ 3,853,266.01** | **$ 8,020,768.17** | **$ 9,020,324.75** | **$ 6,803,011.93** | **$ 4,893,089.04** | **$ 2,529,081.38** | **$ 35,119,541.28** |

**ENERGY NORTH NATURAL GAS, INC**

**NOVEMBER 2011 THROUGH APRIL 2012**
**DETAIL GAS COSTS BY SOURCE**
**SCHEDULE 2B**

| | | | Nov-11 | Dec-11 | Jan-12 | Feb-12 | Mar-12 | Apr-12 | Total |
|---|---|---|---|---|---|---|---|---|---|
| 157 | **FOR THE MONTH OF:** | | | | | | | | |
| 158 | | | | | | | | | |
| 159 | Peak Demand 175.20 | | $ 1,116,442.69 | $ 971,266.53 | $ 1,270,529.29 | $ 1,241,432.15 | $ 955,125.81 | $ 890,965.56 | $ 6,445,762.03 |
| 160 | Peak Commodity 175.20 | | 3,853,266.01 | 8,020,768.17 | 9,020,324.75 | 6,803,011.93 | 4,893,089.04 | 2,529,081.38 | 35,119,541.28 |
| 161 | Total Peak Gas Costs | | **$ 4,969,708.70** | **$ 8,992,034.70** | **$ 10,290,854.04** | **$ 8,044,444.08** | **$ 5,848,214.85** | **$ 3,420,046.94** | **$ 41,565,303.31** |
| 162 | | | | | | | | | |
| 163 | Off-Peak Demand 175.40 | OP | - | - | - | - | (748,632.15) | - | (748,632.15) |
| 164 | Off-Peak Comm 175.40 | OP | - | - | - | - | - | - | - |
| 165 | Total Off-Peak Gas Costs | | $ - | $ - | $ - | $ - | $ (748,632.15) | $ - | $ (748,632.15) |
| 166 | | | | | | | | | |
| 167 | Firm Sendout Costs | | **$ 4,969,708.70** | **$ 8,992,034.70** | **$ 10,290,854.04** | **$ 8,044,444.08** | **$ 5,099,582.70** | **$ 3,420,046.94** | **$ 40,816,671.16** |

**ENERGY NORTH NATURAL GAS, INC**

**NOVEMBER 2011 THROUGH APRIL 2012**
**SCHEDULE 3**
**WINTER CGAC GAS REVENUES BILLED**

| | FOR MONTH OF: | Nov-11 | Nov-11 | Dec-11 | Jan-12 | Feb-12 | Mar-12 | Apr-12 | May-12 | Total | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | OffPeak | Peak | | | | | | Peak | Peak | OffPeak |
| 1 | **VOLUMES** | | | | | | | | | | |
| 2 | **RESIDENTIAL** | | | | | | | | | | |
| 3 | R-1 | 47,895 | 14,708 | 77,909 | 102,345 | 102,236 | 94,088 | 69,436 | 48,003 | **508,725** | **47,895** |
| 4 | R-1 FPO | 3,158 | 1,669 | 8,023 | 10,158 | 9,996 | 9,706 | 6,833 | 4,028 | **50,413** | **3,158** |
| 5 | R-3 | 2,068,685 | 1,057,279 | 4,686,326 | 6,824,203 | 6,953,795 | 6,272,017 | 3,676,027 | 1,646,587 | **31,116,234** | **2,068,685** |
| 6 | R-3 FPO | 274,247 | 173,844 | 810,726 | 1,116,575 | 1,142,461 | 1,034,094 | 615,412 | 287,402 | **5,180,514** | **274,247** |
| 7 | R-4 | 42,182 | 4,393 | 22,780 | 620,250 | 511,494 | 584,265 | 448,041 | 276,855 | **2,468,078** | **42,182** |
| 8 | R-4 FPO | 1,939 | 1,054 | 6,411 | 139,308 | 103,704 | 112,036 | 73,081 | 41,201 | **476,795** | **1,939** |
| 9 | Total Residential | 2,438,106 | 1,252,947 | 5,612,175 | 8,812,839 | 8,823,686 | 8,106,206 | 4,888,830 | 2,304,076 | | |
| 10 | **COMMERCIAL/INDUSTRIAL** | | | | | | | | | | |
| 11 | G41 - G43 | 1,166,134 | 557,358 | 2,837,938 | 4,654,629 | 4,774,127 | 4,175,738 | 2,400,833 | 1,122,655 | **20,523,278** | **1,166,134** |
| 12 | G41 - G43 (FPO) | 69,442 | 48,182 | 260,350 | 416,864 | 417,406 | 325,587 | 209,339 | 100,784 | **1,778,512** | **69,442** |
| 13 | Total G41- G43 | 1,235,576 | 605,540 | 3,098,288 | 5,071,493 | 5,191,533 | 4,501,325 | 2,610,172 | 1,223,439 | | |
| 14 | G51 - G63 | 323,545 | 134,003 | 529,541 | 674,613 | 652,853 | 591,829 | 448,790 | 288,774 | **3,320,403** | **323,545** |
| 15 | G51 - G63 (FPO) | 15,965 | 12,272 | 59,528 | 62,499 | 70,330 | 64,571 | 49,628 | 30,135 | **348,963** | **15,965** |
| 16 | Total G51-G63 | 339,510 | 146,275 | 589,069 | 737,112 | 723,183 | 656,400 | 498,418 | 318,909 | | |
| 17 | Total Sales Volumes | 4,013,192 | 2,004,762 | 9,299,532 | 14,621,444 | 14,738,402 | 13,263,931 | 7,997,420 | 3,846,424 | **65,771,915** | **4,013,192** |
| 18 | **TRANSPORTATION** | | | | | | | | | | |
| 19 | G41 - G43 | 1,321,701 | 403,760 | 2,577,400 | 3,708,448 | 3,933,688 | 3,663,258 | 2,517,136 | 1,387,976 | **18,191,666** | **1,321,701** |
| 20 | G51 - G63 | 2,361,903 | 89,955 | 2,592,439 | 2,824,294 | 2,812,250 | 2,815,446 | 2,513,878 | 2,322,227 | **15,970,489** | **2,361,903** |
| 21 | Total Transportation Volumes | 3,683,604 | 493,715 | 5,169,839 | 6,532,742 | 6,745,938 | 6,478,704 | 5,031,014 | 3,710,203 | **34,162,155** | **3,683,604** |
| 22 | **Total Volumes** | **7,696,796** | **2,498,477** | **14,469,371** | **21,154,186** | **21,484,340** | **19,742,635** | **13,028,434** | **7,556,627** | **99,934,070** | **7,696,796** |
| 23 | | | | | | | | | | | |
| 24 | **RATES** | | | | | | | | | | |
| 25 | Residential | 0.74030 | 0.77300 | 0.75530 | 0.71150 | 0.69710 | 0.68890 | 0.70220 | 0.72640 | | |
| 26 | Residential (FPO) | 0.74030 | 0.7930 | 0.79300 | 0.79300 | 0.79300 | 0.79300 | 0.79300 | 0.79300 | | |
| 27 | C/I Sales G41 to G43 | 0.74420 | 0.77330 | 0.75670 | 0.71200 | 0.69770 | 0.68910 | 0.70150 | 0.72670 | | |
| 28 | C/I Sales G41 to G43 (FPO) | 0.74420 | 0.7933 | 0.79330 | 0.79330 | 0.79330 | 0.79330 | 0.79330 | 0.79330 | | |
| 29 | C/I Transport G41 to G43 | 0.00000 | 0.0000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | | |
| 30 | C/I Sales G51 to G63 | 0.73330 | 0.77150 | 0.75420 | 0.71020 | 0.69570 | 0.68740 | 0.70070 | 0.72490 | | |
| 31 | C/I Sales G51 to G63 (FPO) | 0.73330 | 0.7915 | 0.79150 | 0.79150 | 0.79150 | 0.79150 | 0.79150 | 0.79150 | | |
| 32 | C/I Transport G51 to G63 | 0.00000 | 0.0000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | | |
| 33 | | | | | | | | | | | |
| 34 | **REVENUES** | | | | | | | | | | |
| 35 | Residential | $ 1,598,132 | $ 832,042 | $ 3,615,632 | $ 5,369,547 | $ 5,275,322 | $ 4,788,110 | $ 2,944,679 | $ 1,432,058 | **$ 24,257,389** | **$ 1,598,132** |
| 36 | Residential (FPO) | $ 206,798 | $ 140,018 | $ 654,352 | $ 1,003,971 | $ 996,136 | $ 916,578 | $ 551,394 | $ 263,776 | **$ 4,526,224** | **$ 206,798** |
| 37 | C/I Sales G41 to G43 | $ 867,837 | $ 431,005 | $ 2,147,468 | $ 3,314,096 | $ 3,330,908 | $ 2,877,501 | $ 1,684,184 | $ 815,833 | **$ 14,600,996** | **$ 867,837** |
| 38 | C/I Sales G41 to G43 (FPO) | $ 51,679 | $ 38,223 | $ 206,536 | $ 330,698 | $ 331,128 | $ 258,288 | $ 166,069 | $ 79,952 | **$ 1,410,894** | **$ 51,679** |
| 39 | C/I Transport G41 to G43 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | **$ -** |
| 40 | C/I Sales G51 to G63 | $ 237,256 | $ 103,383 | $ 399,380 | $ 479,110 | $ 454,190 | $ 406,823 | $ 314,467 | $ 209,332 | **$ 2,366,686** | **$ 237,256** |
| 41 | C/I Sales G51 to G63 (FPO) | $ 11,707 | $ 9,713 | $ 47,116 | $ 49,468 | $ 55,666 | $ 51,108 | $ 39,281 | $ 23,852 | **$ 276,204** | **$ 11,707** |
| 42 | C/I Transport G51 to G63 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | **$ -** |
| 43 | **Winter Gas Cost Rev filed** | **$ 2,973,408** | **$ 1,554,384** | **$ 7,070,484** | **$ 10,546,889** | **$ 10,443,350** | **$ 9,298,408** | **$ 5,700,073** | **$ 2,824,803** | **$ 47,438,391** | **$ 2,973,408** |
| 44 | | | | | | | | | | | |
| 45 | Winter Proration | $ - | $ 7,604 | $ (15,761) | $ 2,955 | $ 5,018 | $ 3,084 | $ 3,901 | $ - | **6,801** | **-** |
| 46 | | | | | | | | | | | |
| 47 | Less Occupant Billing | $ 3,121 | $ - | $ 714 | $ 1,052 | $ 1,675 | $ 862 | $ 555 | $ - | **4,858** | **3,121** |
| 48 | Total | $ 2,970,287 | $ 1,561,988 | $ 7,054,008 | $ 10,548,793 | $ 10,446,693 | $ 9,300,630 | $ 5,703,419 | $ 2,824,803 | $ 47,440,335 | $ 2,970,287 |
| 49 | | | | | | | | | | | |
| 50 | **Summer Gas Cost Billed (Acct 175.40)** | **$ 2,970,287** | | | | | | | | | **$ 2,973,408** |
| 51 | | | | | | | | | | | |
| 52 | Winter Gas Costs Billed (Acct 175.20) | | **$ 1,561,988** | **$ 7,054,008** | **$ 10,548,793** | **$ 10,446,693** | **$ 9,300,630** | **$ 5,703,419** | **$ 2,824,803** | **$ 47,440,335** | |
| 53 | Winter Transportation Gas Costs Billed (Acct 175.20) | - | - | - | - | - | - | - | - | **$ -** | **$ -** |
| 54 | **Total Winter Gas Cost Billed (Acct 175.20)** | **$ -** | **$ 1,561,988** | **$ 7,054,008** | **$ 10,548,793** | **$ 10,446,693** | **$ 9,300,630** | **$ 5,703,419** | **$ 2,824,803** | **$ 47,440,335** | **$ 2,973,408** |
| 55 | | | | | | | | | | | |
| 56 | | | | | | | | | | | |
| 57 | Total Sales CGA Billed | **$ 2,970,287** | **$ 1,561,988** | **$ 7,054,008** | **$ 10,548,793** | **$ 10,446,693** | **$ 9,300,630** | **$ 5,703,419** | **$ 2,824,803** | **$ 47,440,335** | **$ 2,970,287** |
| 58 | | | | | | | | | | | |
| 59 | Plus: Working Capital Gas Cost Billed | 1,204 | 2,005 | 9,300 | 14,621 | 14,738 | 13,264 | 7,997 | 3,846 | **65,772** | **1,204** |
| 60 | Plus: Bad Debt Cost Billed | 71,836 | 37,289 | 172,971 | 271,959 | 274,134 | 246,709 | 148,752 | 71,543 | **1,223,358** | **71,836** |
| 61 | Plus: Broker Revenues | - | 59,962 | 52,719 | 37,893 | 51,607 | 10,518 | 38,091 | - | **250,791** | **-** |
| 62 | | | | | | | | | | | |
| 63 | **Total Winter Gas Costs Billed** | **$ 3,043,327** | **$ 1,661,244** | **$ 7,288,998** | **$ 10,873,266** | **$ 10,787,173** | **$ 9,571,121** | **$ 5,898,260** | **$ 2,900,193** | **$ 48,980,256** | **$ 3,043,327** |

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**ENERGY NORTH NATURAL GAS, INC**

**NOVEMBER 2011 THROUGH APRIL 2012**
**SCHEDULE 3A- CALCULATION OF UNBILLED GAS COSTS (ACCRUED COG)**

| | FOR MONTH OF: | Oct-11 | Nov-11 | Dec-11 | Jan-12 | Feb-12 | Mar-12 | Apr-12 | Total |
|---|---|---|---|---|---|---|---|---|---|
| 1 | Firm Gas Purchases | | 8,732,260 | 13,558,770 | 17,034,720 | 12,969,750 | 9,381,320 | 6,433,160 | 68,109,980 |
| 2 | Firm Sales | | 2,004,762 | 9,299,532 | 14,621,444 | 14,738,402 | 13,263,931 | 7,997,420 | 61,925,491 |
| 3 | Company Use | | 104,294 | 130,710 | 209,500 | 159,704 | 140,097 | 93,502 | 837,807 |
| 4 | Unaccounted For % | | 3.1% | 3.1% | 3.1% | 3.1% | 3.1% | 3.1% | |
| 5 | Unaccounted For Gas | | 269,827 | 418,966 | 526,373 | 400,765 | 289,883 | 198,785 | 2,104,598 |
| 6 | COG Factor- Gas Cost Only | | $0.7730 | $0.7170 | $0.7005 | $0.6874 | $0.6926 | $0.7264 | |
| 7 | COG Factor- Bad Debt Factor | | $0.0186 | $0.0186 | $0.0186 | $0.0186 | $0.0186 | $0.0186 | |
| 8 | COG Factor- Working Capital Factor | | $0.0010 | $0.0010 | $0.0010 | $0.0010 | $0.0010 | $0.0010 | |
| 9 | | | | | | | | | |
| 10 | Unbilled Volume | | | | | | | | |
| 11 | Beginning Bal | | - | 6,353,377 | 10,062,939 | 11,740,342 | 9,411,221 | 5,098,630 | |
| 12 | Incremental Unbilled | | 6,353,377 | 3,709,562 | 1,677,403 | (2,329,121) | (4,312,591) | (1,856,547) | |
| 13 | Ending Balance | - | 6,353,377 | 10,062,939 | 11,740,342 | 9,411,221 | 5,098,630 | 3,242,084 | |
| 14 | | | | | | | | | |
| 15 | COG Factor- Gas Cost Only | | $0.7730 | $0.7170 | $0.7005 | $0.6874 | $0.6926 | $0.7264 | |
| 16 | Gross Unbilled Gas Cost | $1,880,968 | $4,911,161 | $7,215,127 | $8,224,110 | $6,469,273 | $3,531,311 | $2,355,050 | |
| 17 | | | | | | | | | |
| 18 | Monthly Incremental Gas Cost | | $3,030,192 | $2,303,967 | $1,008,982 | ($1,754,836) | ($2,937,962) | ($1,176,262) | |
| 19 | | | | | | | | | |
| 20 | COG Factor- Bad Debt Only | | $0.0186 | $0.0186 | $0.0186 | $0.0186 | $0.0186 | $0.0186 | |
| 21 | Gross Unbilled Bad Debt Cost | $45,481 | $118,173 | $187,171 | $218,370 | $175,049 | $94,835 | $60,303 | |
| 22 | | | | | | | | | |
| 23 | Monthly Incremental Bad Debt Cost | | $72,692 | $68,998 | $31,200 | ($43,322) | ($80,214) | ($34,532) | |
| 24 | | | | | | | | | |
| 25 | COG Factor- Working Capital Only | | $0.0010 | $0.0010 | $0.0010 | $0.0010 | $0.0010 | $0.0010 | |
| 26 | Gross Unbilled Working Capital Cost | $762 | $6,353 | $10,063 | $11,740 | $9,411 | $5,099 | $3,242 | |
| 27 | | | | | | | | | |
| 28 | Monthly Incremental Working Capital Cost | | $5,591 | $3,710 | $1,677 | ($2,329) | ($4,313) | ($1,857) | |

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**ENERGY NORTH NATURAL GAS, INC**

**NOVEMBER 2011 THROUGH APRIL 2012**
**SCHEDULE 4 - NONFIRM MARGIN**

| | FOR THE MONTH OF: | Nov-11 | Dec-11 | Jan-12 | Feb-12 | Mar-12 | Apr-12 | Total |
|---|---|---|---|---|---|---|---|---|
| 1 | INTERRUPTIBLE | | | | | | | |
| 2 | | | | | | | | |
| 3 | 280 DAY | | | | | | | |
| 4 | | | | | | | | |
| 5 | OFF SYSTEM GAS SALES MARGIN | | | | | | | |
| 6 | PROPANE OFF SYSTEM SALES MARGIN | | | | | | | |
| 7 | | | | | | | | |
| 8 | CAPACITY RELEASE CREDIT | | | | | | | |
| 9 | | | | | | | | |
| 10 | TOTAL NON FIRM MARGIN AND CREDITS | **$ (1,598)** | **$ (2,077)** | **$ (1,860)** | **$ (5,227)** | **$ (5,402)** | **$ (34,082)** | **$ (50,245)** |

REDACTED

**ENERGY NORTH NATURAL GAS, INC**

**NOVEMBER 2011 THROUGH APRIL 2012**
**PEAK PERIOD WORKING CAPITAL**
**ACCOUNT 142.20**
**SCHEDULE 5**

| | FOR THE MONTH OF: | Nov-11 | Dec-11 | Jan-12 | Feb-12 | Mar-12 | Apr-12 | May-12 | Total |
|---|---|---|---|---|---|---|---|---|---|
| | DAYS IN MONTH: | 30 | 31 | 31 | 29 | 31 | 30 | | |
| 1 | BEGINNING BALANCE | **$ 12,372** | $ 10,358 | $ 8,800 | $ 5,597 | $ 3,417 | $ 1,898 | $ 64 | **$ 12,372** |
| 2 | | | | | | | | | |
| 3 | Add: COST ALLOW | 6,314 | 11,425 | 13,076 | 10,217 | 7,426 | 4,303 | | **52,761** |
| 4 | | | | | | | | | |
| 5 | Less: CUSTOMER BILLINGS | (2,005) | (9,300) | (14,621) | (14,738) | (13,264) | (7,997) | (3,846) | **(65,772)** |
| 6 | Estimated Unbilled | (6,353) | (10,063) | (11,740) | (9,411) | (5,099) | (3,242) | | **(45,909)** |
| 7 | Reverse Prior Month Unbilled | - | 6,353 | 10,063 | 11,740 | 9,411 | 5,099 | 3,242 | **45,909** |
| 8 | Subtotal: Accrued Customer Billings | (8,358) | (13,009) | (16,299) | (12,409) | (8,951) | (6,141) | (604) | **(65,772)** |
| 9 | | | | | | | | | |
| 10 | Adjustment | - | - | - | - | - | - | - | - |
| 11 | | | | | | | | | |
| 12 | ENDING BALANCE PRE INTEREST | **10,328** | **8,774** | **5,577** | **3,405** | **1,891** | **61** | **(541)** | **(639)** |
| 13 | | | | | | | | | |
| 14 | MONTH'S AVERAGE BALANCE | 11,350 | 9,566 | 7,189 | 4,501 | 2,654 | 979 | | |
| 15 | | | | | | | | | |
| 16 | INTEREST RATE | 3.25% | 3.25% | 3.25% | 3.25% | 3.25% | 3.25% | | |
| 17 | INTEREST APPLIED | 30 | 26 | 20 | 12 | 7 | 3 | | **98** |
| 18 | ENDING BALANCE | **$ 10,358** | **$ 8,800** | **$ 5,597** | **$ 3,417** | **$ 1,898** | **$ 64** | **$ (541)** | **$ (541)** |

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**ENERGY NORTH NATURAL GAS, INC**

**NOVEMBER 2011 THROUGH APRIL 2012**
**OFF PEAK WORKING CAPITAL**
**ACCOUNT 142.40**
**SCHEDULE 5**

| | FOR THE MONTH OF: | Nov-11 | Dec-11 | Jan-12 | Feb-12 | Mar-12 | Apr-12 | May-12 | Total |
|---|---|---|---|---|---|---|---|---|---|
| | DAYS IN MONTH | 30 | 31 | 31 | 29 | 31 | 30 | | |
| 1 | BEGINNING BALANCE | **$ (614)** | $ (1,057) | $ (1,060) | $ (1,063) | $ (1,066) | $ (2,022) | $ (2,027) | **(614)** |
| 2 | | | | | | | | | |
| 3 | Add:ACTUAL COST | - | - | - | - | (951) | - | | **$ (951)** |
| 4 | | | | | | | | | **0** |
| 5 | Less: CUSTOMER BILLINGS | (1,204) | - | - | - | - | - | - | **(1,204)** |
| 6 | Estimated Unbilled | - | - | - | - | - | - | | - |
| 7 | Reverse Prior Month Unbilled | **762** | - | - | - | - | - | - | **762** |
| 8 | Subtotal: Accrued Customer Billings | (442) | - | - | - | - | - | - | **(442)** |
| 9 | | | | | | | | | |
| 10 | ENDING BALANCE PRE INTEREST | **(1,055)** | **(1,057)** | **(1,060)** | **(1,063)** | **(2,018)** | **(2,022)** | **(2,027)** | **(2,007)** |
| 11 | | | | | | | | | |
| 12 | MONTH'S AVERAGE BALANCE | (834) | (1,057) | (1,060) | (1,063) | (1,542) | (2,022) | | |
| 13 | | | | | | | | | |
| 14 | INTEREST RATE | 3.25% | 3.25% | 3.25% | 3.25% | 3.25% | 3.25% | | |
| 15 | INTEREST APPLIED | (2) | (3) | (3) | (3) | (4) | (5) | | **(20)** |
| 16 | ENDING BALANCE | **$ (1,057)** | **$ (1,060)** | **$ (1,063)** | **$ (1,066)** | **$ (2,022)** | **$ (2,027)** | **$ (2,027)** | **$ (2,027)** |

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**ENERGY NORTH NATURAL GAS, INC**

**NOVEMBER 2011 THROUGH APRIL 2012**
**SCHEDULE 6**
**WINTER BAD DEBT AND WORKING CAPITAL COSTS**

| | FOR MONTH OF: | Nov-11 | Dec-11 | Jan-12 | Feb-12 | Mar-12 | Apr-12 | Total |
|---|---|---|---|---|---|---|---|---|
| 1 | **Demand** | $ 1,114,845 | $ 969,190 | $ 1,268,669 | $ 1,236,206 | $ 949,724 | $ 856,884 | **$ 6,395,517** |
| 2 | **Commodity** | 3,853,266 | 8,020,768 | 9,020,325 | 6,803,012 | 4,893,089 | 2,529,081 | **35,119,541** |
| 3 | **Total Gas Costs** | **$ 4,968,111** | **$ 8,989,958** | **$ 10,288,994** | **$ 8,039,218** | **$ 5,842,813** | **$ 3,385,965** | **$ 41,515,058** |
| 4 | | | | | | | | |
| 5 | **Lead Lag Days** | **0.0391** | **0.0391** | **0.0391** | **0.0391** | **0.0391** | **0.0391** | |
| 6 | **Prime Rate** | **3.25%** | **3.25%** | **3.25%** | **3.25%** | **3.25%** | **3.25%** | |
| 7 | | | | | | | | |
| 8 | **Working Capital Rate 1/** | **0.00127** | **0.00127** | **0.00127** | **0.00127** | **0.00127** | **0.00127** | |
| 9 | | | | | | | | |
| 10 | **Total Working Capital Costs** | **$ 6,314** | **$ 11,425** | **$ 13,076** | **$ 10,217** | **$ 7,426** | **$ 4,303** | **$ 52,761** |
| 11 | | | | | | | | |
| 12 | **Prior Period Undercollection** | **622,550** | **622,550** | **622,550** | **622,550** | **622,550** | **622,550** | **3,735,297** |
| 13 | | | | | | | | |
| 14 | **Subtotal Gas Costs, Working Capital & Under Collection** | 5,596,974 | 9,623,932 | 10,924,620 | 8,671,984 | 6,472,788 | 4,012,818 | **45,303,116** |
| 15 | | | | | | | | |
| 16 | **Bad Debt Rate 1/** | **0.0250** | **0.0250** | **0.0250** | **0.0250** | **0.0250** | **0.0250** | |
| 17 | | | | | | | | |
| 18 | **Total Bad Debt Cost** | **$ 139,872** | **$ 240,508** | **$ 273,013** | **$ 216,718** | **$ 161,759** | **$ 100,283** | **$ 1,132,153** |

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**ENERGY NORTH NATURAL GAS, INC**

**NOVEMBER 2011 THROUGH APRIL 2012**
**SCHEDULE 6**
**SUMMER BAD DEBT AND WORKING CAPITAL COSTS**

| | FOR MONTH OF: | May-11 | Jun-11 | Jul-11 | Aug-11 | Sep-11 | Oct-11 | Total |
|---|---|---|---|---|---|---|---|---|
| 1 | **Demand** | $ 793,934 | $ 1,426,490 | $ 1,044,501 | $ 1,519,111 | $ 1,208,407 | $ 1,406,848 | **$ 7,399,291** |
| 2 | **Commodity** | 2,025,962 | 1,115,424 | 848,156 | 1,004,390 | 1,022,616 | 2,282,537 | **8,299,085** |
| 3 | **Total Gas Costs** | **$ 2,819,896** | **$ 2,541,913** | **$ 1,892,657** | **$ 2,523,501** | **$ 2,231,023** | **$ 3,689,385** | **$ 15,698,376** |
| 4 | | | | | | | | |
| 5 | **Lead Lag Days** | **0.0391** | **0.0391** | **0.0391** | **0.0391** | **0.0391** | **0.0391** | |
| 6 | **Prime Rate** | **3.25%** | **3.25%** | **3.25%** | **3.25%** | **3.25%** | **3.25%** | |
| 7 | | | | | | | | |
| 8 | **Working Capital Rate 1/** | **0.00127** | **0.00127** | **0.00127** | **0.00127** | **0.00127** | **0.00127** | |
| 9 | | | | | | | | |
| 10 | **Total Working Capital Costs** | **$ 3,584** | **$ 3,230** | **$ 2,405** | **$ 3,207** | **$ 2,835** | **$ 4,689** | **$ 19,951** |
| 11 | | | | | | | | |
| 12 | **Prior Period Undercollection** | **(76,695)** | **(76,695)** | **(76,695)** | **(76,695)** | **(76,695)** | **(76,695)** | **(460,169)** |
| 13 | | | | | | | | |
| 14 | **Subtotal Gas Costs, Working Capital & Under Collection** | 2,746,785 | 2,468,449 | 1,818,368 | 2,450,013 | 2,157,164 | 3,617,379 | **15,258,158** |
| 15 | | | | | | | | |
| 16 | **Bad Debt Rate 1/** | **0.0250** | **0.0250** | **0.0250** | **0.0250** | **0.0250** | **0.0250** | |
| 17 | | | | | | | | |
| 18 | **Total Bad Debt Cost** | **$ 68,670** | **$ 61,711** | **$ 45,459** | **$ 61,250** | **$ 53,929** | **$ 90,434** | **$ 381,454** |

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**ENERGY NORTH NATURAL GAS, INC**

**NOVEMBER 2011 THROUGH APRIL 2012**
**SCHEDULE 6**
**WINTER BAD DEBT AND WORKING CAPITAL COSTS**

| | FOR MONTH OF: | May-11 | Jun-11 | Jul-11 | Aug-11 | Sep-11 | Oct-11 | |
|---|---|---|---|---|---|---|---|---|
| 1 | **Monthly Revenue** | $ 9,173,856 | $ 5,610,374 | $ 4,708,239 | $ 4,187,160 | $ 4,390,419 | $ 4,933,311 | |
| 2 | **Charge Off** | 160,502 | 260,084 | 439,473 | 504,172 | 495,202 | 263,825 | |

| | FOR MONTH OF: | Nov-11 | Dec-11 | Jan-12 | Feb-12 | Mar-12 | Apr-12 | Total |
|---|---|---|---|---|---|---|---|---|
| 3 | **Monthly Revenue** | $ 8,992,721 | $ 13,217,665 | $ 18,544,566 | $ 18,409,026 | $ 16,903,722 | $ 11,304,944 | **120,376,003** |
| 4 | **Charge Off** | 230,381 | 202,159 | 125,780 | 94,415 | 121,089 | 111,188 | **3,008,270** |
| 5 | | | | | | | | |
| 6 | | | | | | | | |
| 7 | **Bad Debt Rate** | | | | | | | **0.0250** |

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**ENERGY NORTH NATURAL GAS, INC**

**NOVEMBER 2011 THROUGH APRIL 2012**
**SCHEDULE 7**
**WORKING CAPITAL & BAD DEBT COLLECTED**

| | FOR MONTH OF: | OffPeak Nov-11 | Peak Nov-11 | Dec-11 | Jan-12 | Feb-12 | Mar-12 | Apr-12 | Peak May-12 | Total Peak |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | **VOLUMES** | | | | | | | | | |
| 2 | **RESIDENTIAL** | | | | | | | | | |
| 3 | R-1, R-3 and R-4 | 2,158,762 | 1,076,380 | 4,787,015 | 7,546,798 | 7,567,525 | 6,950,370 | 4,193,504 | 1,971,445 | **34,093,037** |
| 4 | R-1, R-3 and R-4 (FPO) | 279,344 | 176,567 | 825,160 | 1,266,041 | 1,256,161 | 1,155,836 | 695,326 | 332,631 | **5,707,722** |
| 5 | | | | | | | | | | |
| 6 | **COMMERCIAL/INDUSTRIAL** | | | | | | | | | |
| 7 | G41 - G43 | 1,166,134 | 557,358 | 2,837,938 | 4,654,629 | 4,774,127 | 4,175,738 | 2,400,833 | 1,122,655 | **20,523,278** |
| 8 | G41 - G43 (FPO) | 69,442 | 48,182 | 260,350 | 416,864 | 417,406 | 325,587 | 209,339 | 100,784 | **1,778,512** |
| 9 | G51 - G63 | 323,545 | 134,003 | 529,541 | 674,613 | 652,853 | 591,829 | 448,790 | 288,774 | **3,320,403** |
| 10 | G51 - G63 (FPO) | 15,965 | 12,272 | 59,528 | 62,499 | 70,330 | 64,571 | 49,628 | 30,135 | **348,963** |
| 11 | | | | | | | | | | |
| 12 | **TRANSPORTATION** | | | | | | | | | |
| 13 | G41 - G43 | 1,321,701 | 403,760 | 2,577,400 | 3,708,448 | 3,933,688 | 3,663,258 | 2,517,136 | 1,387,976 | **18,191,666** |
| 14 | G51 - G63 | 2,361,903 | 89,955 | 2,592,439 | 2,824,294 | 2,812,250 | 2,815,446 | 2,513,878 | 2,322,227 | **15,970,489** |
| 15 | | | | | | | | | | |
| 16 | **TOTAL VOLUME** | **7,696,796** | **2,498,477** | **14,469,371** | **21,154,186** | **21,484,340** | **19,742,635** | **13,028,434** | **7,556,627** | **99,934,070** |
| 17 | | | | | | | | | | |
| 18 | **WORKING CAPITAL RATES** | | | | | | | | | |
| 19 | Residential R1, R3 & R4 | **$0.0003** | **$0.0010** | **$0.0010** | **$0.0010** | **$0.0010** | **$0.0010** | **$0.0010** | **$0.0010** | |
| 20 | Residential R1, R-3 & R4 (FPO) | **$0.0003** | **$0.0010** | **$0.0010** | **$0.0010** | **$0.0010** | **$0.0010** | **$0.0010** | **$0.0010** | |
| 21 | C/I Sales G41 to G43 | **$0.0003** | **$0.0010** | **$0.0010** | **$0.0010** | **$0.0010** | **$0.0010** | **$0.0010** | **$0.0010** | |
| 22 | C/I Sales G41 to G43 (FPO) | **$0.0003** | **$0.0010** | **$0.0010** | **$0.0010** | **$0.0010** | **$0.0010** | **$0.0010** | **$0.0010** | |
| 23 | C/I Sales G51 to G63 | **$0.0003** | **$0.0010** | **$0.0010** | **$0.0010** | **$0.0010** | **$0.0010** | **$0.0010** | **$0.0010** | |
| 24 | C/I Sales G51 to G63 (FPO) | **$0.0003** | **$0.0010** | **$0.0010** | **$0.0010** | **$0.0010** | **$0.0010** | **$0.0010** | **$0.0010** | |
| 25 | | | | | | | | | | |
| 26 | **WORKING CAPITAL COSTS COLLECTED** | | | | | | | | | |
| 27 | Residential | $ 648 | $ 1,076 | $ 4,787 | $ 7,547 | $ 7,568 | $ 6,950 | $ 4,194 | $ 1,971 | **$ 34,093** |
| 28 | Residential (FPO) | 84 | 177 | 825 | 1,266 | 1,256 | 1,156 | 695 | 333 | **5,708** |
| 29 | C/I Sales G41 to G43 | 350 | 557 | 2,838 | 4,655 | 4,774 | 4,176 | 2,401 | 1,123 | **20,523** |
| 30 | C/I Sales G41 to G43 (FPO) | 21 | 48 | 260 | 417 | 417 | 326 | 209 | 101 | **1,779** |
| 31 | C/I Sales G51 to G63 | 97 | 134 | 530 | 675 | 653 | 592 | 449 | 289 | **3,320** |
| 32 | C/I Sales G51 to G63 (FPO) | 5 | 12 | 60 | 62 | 70 | 65 | 50 | 30 | **349** |
| 33 | | | | | | | | | | |
| 34 | **SUMMER GAS COST WORKING CAPITAL COLLEC** | **$ 1,204** | **$ 2,005** | **$ 9,300** | **$ 14,621** | **$ 14,738** | **$ 13,264** | **$ 7,997** | **$ 3,846** | **$ 65,772** |
| 35 | | | | | | | | | | |
| 36 | **BAD DEBT RATES** | | | | | | | | | |
| 37 | Residential R1, R3 & R4 | **$0.0179** | **$0.0186** | **$0.0186** | **$0.0186** | **$0.0186** | **$0.0186** | **$0.0186** | **$0.0186** | |
| 38 | Residential R1 & R3 (FPO) | **$0.0179** | **$0.0186** | **$0.0186** | **$0.0186** | **$0.0186** | **$0.0186** | **$0.0186** | **$0.0186** | |
| 39 | C/I Sales G41 to G43 | **$0.0179** | **$0.0186** | **$0.0186** | **$0.0186** | **$0.0186** | **$0.0186** | **$0.0186** | **$0.0186** | |
| 40 | C/I Sales G41 to G43 (FPO) | **$0.0179** | **$0.0186** | **$0.0186** | **$0.0186** | **$0.0186** | **$0.0186** | **$0.0186** | **$0.0186** | |
| 41 | C/I Sales G51 to G63 | **$0.0179** | **$0.0186** | **$0.0186** | **$0.0186** | **$0.0186** | **$0.0186** | **$0.0186** | **$0.0186** | |
| 42 | C/I Sales G51 to G63 (FPO) | **$0.0179** | **$0.0186** | **$0.0186** | **$0.0186** | **$0.0186** | **$0.0186** | **$0.0186** | **$0.0186** | |
| 43 | | | | | | | | | | |
| 44 | **BAD DEBTS COLLECTED** | | | | | | | | | |
| 45 | Residential R1, R3 & R4 | $ 38,642 | $ 20,021 | $ 89,038 | $ 140,370 | $ 140,756 | $ 129,277 | $ 77,999 | $ 36,669 | **$ 634,130** |
| 46 | Residential R1, R-3 & R4 (FPO) | 5,000 | 3,284 | 15,347.98 | 23,548.36 | 23,364.59 | 21,498.55 | 12,933.06 | 6,186.94 | **106,164** |
| 47 | C/I Sales G41 to G43 | 20,874 | 10,367 | 52,785.65 | 86,576.10 | 88,798.76 | 77,668.73 | 44,655.49 | 20,881.38 | **381,733** |
| 48 | C/I Sales G41 to G43 (FPO) | 1,243 | 896 | 4,842.51 | 7,753.67 | 7,763.75 | 6,055.92 | 3,893.71 | 1,874.58 | **33,080** |
| 49 | C/I Sales G51 to G63 | 5,791 | 2,492 | 9,849.46 | 12,547.80 | 12,143.07 | 11,008.02 | 8,347.49 | 5,371.20 | **61,759** |
| 50 | C/I Sales G51 to G63 (FPO) | 286 | 228 | 1,107.22 | 1,162.48 | 1,308.14 | 1,201.02 | 923.08 | 560.51 | **6,491** |
| 51 | | | | | | | | | | |
| 52 | **SUMMER BAD DEBTS COLLECTED** | **$ 71,836** | **$ 37,289** | **$ 172,971** | **$ 271,959** | **$ 274,134** | **$ 246,709** | **$ 148,752** | **$ 71,543** | **$ 1,223,358** |

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**ENERGY NORTH NATURAL GAS, INC**

**NOVEMBER 2011 THROUGH APRIL 2012**
**COMMODITY AND RELATED VOLUMES**
**SCHEDULE 8**

| | FOR THE MONTH OF: | Nov-11 | | Dec-11 | | Jan-12 | | Feb-12 | | Mar-12 | | Apr-12 | | Total | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Dollar | Volume Dkt | Dollar | Volume Dkt | Dollar | Volume Dkt | Dollar | Volume Dkt | Dollar | Volume Dkt | Dollar | Volume Dkt | **Dollar** | **Volume Dkt** |
| | **TENNESEE COMMODITY** | | | | | | | | | | | | | | |
| 1 | Gas Supply | | | | | | | | | | | | | | |
| 2 | Off System Sales Gas Costs | | | | | | | | | | | | | | |
| 3 | Pipeline Transport | | | | | | | | | | | | | | |
| 4 | Storage Injections | | | | | | | | | | | | | | |
| 5 | TOTAL TENNESSEE | | | | | | | | | | | | | | |
| 6 | | | | | | | | | | | | | | | |
| 7 | | | | | | | | | | | | | | | |
| 8 | | | | | | | | | | | | | | | |
| 9 | City Gate Supply | | | | | | | | | | | | | | |
| 10 | | | | | | | | | | | | | | | |
| 11 | Dracut Supply | | | | | | | | | | | | | | |
| 12 | | | | | | | | | | | | | | | |
| 13 | | | | | | | | | | | | | | | |
| 14 | **CANADIAN COMMODITY** | | | | | | | | | | | | | | |
| 15 | PNGTS Supply | | | | | | | | | | | | | | |
| 16 | TOTAL PNGTS | | | | | | | | | | | | | | |
| 17 | | | | | | | | | | | | | | | |
| 18 | BP/Northeast Gas Market | | | | | | | | | | | | | | |
| 19 | SHELL CANADIAN | | | | | | | | | | | | | | |
| 20 | NEXEN | | | | | | | | | | | | | | |
| 21 | TOTAL TGP/Niagara | | | | | | | | | | | | | | |
| 22 | | | | | | | | | | | | | | | |
| 23 | ANE Dawn-Iroquois | | | | | | | | | | | | | | |
| 24 | ANE Union/Transgas Transporation | | | | | | | | | | | | | | |
| 25 | TOTAL TGP/Iroquois Commodity | | | | | | | | | | | | | | |
| 26 | | | | | | | | | | | | | | | |
| 27 | | | | | | | | | | | | | | | |
| 28 | **LNG** | | | | | | | | | | | | | | |
| 29 | Distrigas (FCS 064) | | | | | | | | | | | | | | |
| 30 | | | | | | | | | | | | | | | |
| 31 | LNG Vapor - P/S Plant | | | | | | | | | | | | | | |
| 32 | LNG Injections | | | | | | | | | | | | | | |
| 33 | Subtotal LNG | | | | | | | | | | | | | | |
| 34 | | | | | | | | | | | | | | | |
| 35 | | | | | | | | | | | | | | | |
| 36 | **Propane** | | | | | | | | | | | | | | |
| 37 | Off System Sales | | | | | | | | | | | | | | |
| 38 | Propane Sendout - P/S Plant | | | | | | | | | | | | | | |
| 39 | EN Propane - Tank Farm | | | | | | | | | | | | | | |
| 40 | Total Propane | | | | | | | | | | | | | | |
| 41 | | | | | | | | | | | | | | | |
| 42 | | | | | | | | | | | | | | | |
| 43 | Storage Withdrawals | | | | | | | | | | | | | | |
| 44 | | | | | | | | | | | | | | | |
| 45 | | | | | | | | | | | | | | | |
| 46 | Hedging (Gains) Loses | | | | | | | | | | | | | | |
| 47 | | | | | | | | | | | | | | | |
| 48 | Supplier Cashouts | | | | | | | | | | | | | | |
| 49 | | | | | | | | | | | | | | | |
| 50 | Capacity Managed - Canadian | | | | | | | | | | | | | | |
| 51 | | | | | | | | | | | | | | | |
| 52 | Taxes | | | | | | | | | | | | | | |
| 53 | | | | | | | | | | | | | | | |
| 54 | Non-Firm Costs | | | | | | | | | | | | | | |
| 55 | | | | | | | | | | | | | | | |
| 56 | | | | | | | | | | | | | | | |
| 57 | **NET COMMODITY COST** | **$ 3,853,266** | **873,226** | **$ 8,020,768** | **1,355,877** | **$ 9,020,325** | **1,703,472** | **$ 6,803,012** | **1,296,975** | **$ 4,893,089** | **938,132** | **$ 2,529,081** | **643,316** | **$ 35,119,541** | **6,810,998** |

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**ENERGY NORTH NATURAL GAS, INC**

**NOVEMBER 2011 THROUGH APRIL 2012**
**MONTHLY PRIME RATES**
**SCHEDULE 9**

| MONTH | DATES | PRIME RATE | DAYS IN MONTH | WEIGHTED RATE |
|---|---|---|---|---|
| Nov-11 | 11/01 - 11/30 | **3.25%** | 30 | 3.2500% |
| Dec-11 | 12/01 - 012/31 | **3.25%** | 31 | 3.2500% |
| Jan-12 | 01/01 - 01/31 | **3.25%** | 31 | 3.2500% |
| Feb-12 | 02/01 - 02/29 | **3.25%** | 29 | 3.2500% |
| Mar-12 | 03/01 - 03/31 | **3.25%** | 31 | 3.2500% |
| Apr-12 | 04/01 - 04/30 | **3.25%** | 30 | 3.2500% |

**Local Distribution Adjustment Charge Calculation**

| | | Sales Customers | Transporatation Customers | | Reference |
|---|---|---|---|---|---|
| **Residential Non Heating Rates - R-1** | | | | | |
| Energy Efficiency Charge | $0.0147 | | | | Energy Efficiency Page 1 |
| Demand Side Management Charge | 0.0000 | | | | |
| Conservation Charge (CCx) | | $0.0147 | | | |
| Relief Holder and pond at Gas Street, Concord, NH | 0.0000 | | | | |
| Manufactured Gas Plants | 0.0011 | | | | Proposed First Revised Page 91 |
| Environmental Surcharge (ES) | | 0.0011 | | | |
| Cost Allowance Adjustment Factor | | 0.0000 | | | Cost Allowance Factor |
| Rate Case Expense Factor (RCEF) | | 0.0027 | | | Rate Case Expense Calculation |
| Residential Low Income Assistance Program (RLIAP) | | 0.0073 | | | RILAP Page 1 |
| **LDAC** | | **$0.0258** | | **per therm** | |
| **Residential Heating Rates - R-3, R-4** | | | | | |
| Energy Efficiency Charge | $0.0147 | | | | Energy Efficiency Page 1 |
| Demand Side Management Charge | 0.0000 | | | | Conservation Charge |
| Conservation Charge (CCx) | | $0.0147 | | | |
| Relief Holder and pond at Gas Street, Concord, NH | 0.0000 | | | | |
| Manufactured Gas Plants | 0.0011 | | | | Proposed First Revised Page 91 |
| Environmental Surcharge (ES) | | 0.0011 | | | |
| Cost Allowance Adjustmern Factor | | 0.0000 | | | Cost Allowance Factor |
| Rate Case Expense Factor (RCEF) | | 0.0027 | | | Rate Case Expense Calculation |
| Residential Low Income Assistance Program (RLIAP) | | 0.0073 | | | RILAP Page 1 |
| **LDAC** | | **$0.0258** | | **per therm** | |
| **Commercial/Industrial Low Annual Use Rates - G-41, G-51** | | | | | |
| Energy Efficiency Charge | $0.0076 | | | | Energy Efficiency Page 1 |
| Demand Side Management Charge | 0.0000 | | | | Conservation Charge |
| Conservation Charge (CCx) | | $0.0076 | $0.0076 | | |
| Relief Holder and pond at Gas Street, Concord, NH | 0.0000 | | | | |
| Manufactured Gas Plants | 0.0011 | | | | Proposed First Revised Page 91 |
| Environmental Surcharge (ES) | | 0.0011 | 0.0011 | | |
| Cost Allowance Adjustmern Factor | | 0.0000 | 0.0000 | | Cost Allowance Factor |
| Gas Restructuring Expense Factor (GREF) | | 0.0000 | 0.0000 | | |
| Rate Case Expense Factor (RCEF) | | 0.0027 | 0.0027 | | Rate Case Expense Calculation |
| Residential Low Income Assistance Program (RLIAP) | | 0.0073 | 0.0073 | | RILAP Page 1 |
| **LDAC** | | **$0.0187** | **$0.0187** | **per therm** | |
| **Commercial/Industrial Medium Annual Use Rates - G-42, G-52** | | | | | |
| Energy Efficiency Charge | $0.0076 | | | | Energy Efficiency Page 1 |
| Demand Side Management Charge | 0.0000 | | | | Conservation Charge |
| Conservation Charge (CCx) | | $0.0076 | $0.0076 | | |
| Relief Holder and pond at Gas Street, Concord, NH | 0.0000 | | | | |
| Manufactured Gas Plants | 0.0011 | | | | Proposed First Revised Page 91 |
| Environmental Surcharge (ES) | | 0.0011 | 0.0011 | | |
| Cost Allowance Adjustmern Factor | | 0.0000 | 0.0000 | | Cost Allowance Factor |
| Gas Restructuring Expense Factor (GREF) | | 0.0000 | 0.0000 | | |
| Rate Case Expense Factor (RCEF) | | 0.0027 | 0.0027 | | Rate Case Expense Calculation |
| Residential Low Income Assistance Program (RLIAP) | | 0.0073 | 0.0073 | | RILAP Page 1 |
| **LDAC** | | **$0.0187** | **$0.0187** | **per therm** | |
| **Commercial/Industrial Large Annual Use Rates - G-43, G-53, G-54** | | | | | |
| Energy Efficiency Charge | $0.0076 | | | | Energy Efficiency Page 1 |
| Demand Side Management Charge | 0.0000 | | | | Conservation Charge |
| Conservation Charge (CCx) | | $0.0076 | $0.0076 | | |
| Relief Holder and pond at Gas Street, Concord, NH | 0.0000 | | | | |
| Manufactured Gas Plants | 0.0011 | | | | Proposed First Revised Page 91 |
| Environmental Surcharge (ES) | | 0.0011 | 0.0011 | | |
| Cost Allowance Adjustmern Factor | | 0.0000 | 0.0000 | | Cost Allowance Factor |
| Gas Restructuring Expense Factor (GREF) | | 0.0000 | 0.0000 | | |
| Rate Case Expense Factor (RCEF) | | 0.0027 | 0.0027 | | Rate Case Expense Calculation |
| Residential Low Income Assistance Program (RLIAP) | | 0.0073 | 0.0073 | | RILAP Page 1 |
| **LDAC** | | **$0.0187** | **$0.0187** | **per therm** | |

## Rate Case Expense/Temporary Rate Reconciliation (RDE) Factor Calculation

**Rate Case Expense Factors for Resdential Customers**

| | | |
|---|---|---|
| Rate Case Expense (Balance 07/31/12) | $ | 623,004 |
| Temporary Rate Reconciliation - DG 10-017 | | - |
| Sipulation per Settlement Argument - DG 10-017 | | - |
| Reconciliation DG 08-009 and Merger Incentive DG 06-707 | | - |
| Total Rate Case Expense/Temporary Rate Reconciliation Recoverable | $ | 623,004 |
| OffPeak 2012 Rate Case Expense Factor | $ | 0.0116 |
| OffPeak 2012 Projected Volumes (Aug-Oct) | | 16,967,216 |
| OffPeak 2012 Rate Case Expense Projected Collection (Aug-Oct) | | 197,035 |
| OffPeak 2012 Rate Case Expense Projected Interest (Aug-Oct) | | 4,804 |
| Total Net Rate Case Expense/Temporary Rate Reconciliation Recoverable | | 430,773 |
| Forecasted Annual Throughput Volumes for Residential Customer (A:VOLres) | | 57,541,620 |
| Forecasted Annual Throughput Volumes for Commercial/Industrial Customer (A:VOLc&i) | | 100,520,729 |
| Total Volumes | | 158,062,349 |
| **Rate Case Expense Factor** | $ | 0.0027 |

## DG 06-107 Merger Settlement - Emergency Response Incentive

**Emergency Response Merger Incentive**

| | | |
|---|---|---|
| Merger Incentive - Emergency Response | $ | - |

| | |
|---|---|
| Forecasted Annual Throughput Volumes for Residential Customer (A:VOLres) | 58,353,540 |
| Forecasted Annual Throughput Volumes for Commercial/Industrial Customer (A:VOLc&i) | 92,474,643 |
| Total Volumes | 150,828,182 |

| | | |
|---|---|---|
| **Rate Case Expense Factor** | $ | - |

**ENERGY NORTH NATURAL GAS, INC.**

**Residential Low Income Assistance Program (RLIAP)**

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 1 | **Peak Period** | **Customer Charge** | | **First Block** | | **Last Block** | | **Total** |
| 2 | R-3 Base Rates | $ | 17.3100 | $ | 0.2739 | $ | 0.2263 | |
| 3 | R-4 Rate at 40% of R-3 | $ | 6.9200 | $ | 0.1096 | $ | 0.0905 | |
| 4 | Program Subsidy | $ | 10.3900 | $ | 0.1643 | $ | 0.1358 | |
| 5 | Average Annual Therms | | | | 572 | | 203 | 775 |
| 6 | | | | | | | | |
| 7 | Peak Period RLIAP Subsidy | $ | 62.34 | $ | 94.01 | $ | 27.55 | $ 183.90 |
| 8 | | | | | | | | |
| 9 | **Off Peak Period** | | | | | | | |
| 10 | R-3 Base Rates | $ | 17.3100 | $ | 0.2739 | $ | 0.2263 | |
| 11 | R-4 Rate at 40% of R-3 | $ | 6.9200 | $ | 0.1096 | $ | 0.0905 | |
| 12 | Program Subsidy | $ | 10.3900 | $ | 0.1643 | $ | 0.1358 | |
| 13 | Average Annual Therms | | | | 118 | | 52 | 170 |
| 14 | | | | | | | | |
| 15 | Off Peak Period RLIAP Subsidy | $ | 62.34 | $ | 19.42 | $ | 7.07 | $ 88.83 |
| 16 | | | | | | | | |
| 17 | Estimated Annual Subsidy | $ | 124.68 | $ | 113.43 | $ | 34.62 | $ 272.74 |
| 18 | | | | | | | | |
| 19 | Number of Estimated 2012/13 Participants | | | | | | | 5,485 1/ |
| 20 | | | | | | | | |
| 21 | Annual Subsidy times Number of Particpants (Ln 17 * Ln 19) | | | | | | | $ 1,495,954 |
| 22 | Prior Year Ending Balance - RLIAP Page 2 | | | | | | | (347,982) |
| 23 | Estimated Annual Administrative Costs | | | | | | | 8,600 |
| 24 | Total Program Costs | | | | | | | $ 1,156,572 |
| 25 | | | | | | | | |
| 26 | Estimated weather normalized firm therms billed for the | | | | | | | |
| 27 | twelve months ended 10/31/13 sales and transportation | | | | | | | 158,062,349 |
| 28 | | | | | | | | |
| 29 | **Total Residential Low Income Program Charge** | | | | | | | **$ 0.0073** |

1/ Estimated number of participants for 2012-13 is based on the actual number participants as of June 2012, as provided in the RLIAP Quarterly Report as revised and filed on July 27, 2012.

**ENERGY NORTH NATURAL GAS, INC.**

**NOVEMBER 2011 THROUGH OCTOBER 2012**
**RESIDENTIAL LOW INCOME ASSISTANCE PROGRAM RECONCILIATION**
**ACCOUNT 175.39**

| | | | | | | | | | | (Estimate) | (Estimate) | (Estimate) | (Estimate) | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | **FOR THE MONTH OF:** | **Nov-11** | **Dec-11** | **Jan-12** | **Feb-12** | **Mar-12** | **Apr-12** | **May-12** | **Jun-12** | **Jul-12** | **Aug-12** | **Sep-12** | **Oct-12** | **Total** |
| 2 | **DAYS IN MONTH** | **30** | **31** | **31** | **29** | **31** | **30** | **31** | **30** | **31** | **31** | **30** | **31** | |
| 3 | Beginning Balance | $ (339,001) | $ (432,258) | $ (558,608) | $ (535,648) | $ (580,681) | $ (584,556) | $ (550,971) | $ (510,885) | $ (492,685) | $ (457,636) | $ (418,857) | $ (383,571) | $ (339,001) |
| 4 | | | | | | | | | | | | | | |
| 5 | Add: Actual Costs | 20,040 | 8,134 | 219,086 | 154,062 | 179,363 | 154,962 | 129,488 | 79,615 | 90,563 | 88,581 | 88,833 | 98,794 | 1,311,522 |
| 6 | | | | | | | | | | | | | | |
| 7 | Less: Collected Revenue | (112,269) | (133,118) | (194,619) | (197,656) | (181,632) | (119,862) | (87,939) | (60,076) | (54,204) | (48,593) | (52,477) | (62,196) | (1,304,642) |
| 8 | | | | | | | | | | | | | | |
| 9 | Add: Administrative and Start Up Costs | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 10 | | | | | | | | | | | | | | |
| 11 | Ending Balance Pre-Interest | $ (431,230) | $ (557,242) | $ (534,140) | $ (579,242) | $ (582,950) | $ (549,456) | $ (509,421) | $ (491,346) | $ (456,326) | $ (417,649) | $ (382,501) | $ (346,974) | **$ (332,121)** |
| 12 | | | | | | | | | | | | | | |
| 13 | Month's Average Balance | $ (385,115) | $ (494,750) | $ (546,374) | $ (557,445) | $ (581,816) | $ (567,006) | $ (530,196) | $ (501,115) | $ (474,505) | $ (437,642) | $ (400,679) | $ (365,272) | |
| 14 | | | | | | | | | | | | | | |
| 15 | Interest Rate | 3.25% | 3.25% | 3.25% | 3.25% | 3.25% | 3.25% | 3.25% | 3.25% | 3.25% | 3.25% | 3.25% | 3.25% | |
| 16 | | | | | | | | | | | | | | |
| 17 | Interest Applied | $ (1,029) | $ (1,366) | $ (1,508) | $ (1,439) | $ (1,606) | $ (1,515) | $ (1,463) | $ (1,339) | $ (1,310) | $ (1,208) | $ (1,070) | $ (1,008) | **(15,861)** |
| 18 | | | | | | | | | | | | | | |
| 19 | Ending Balance | **$ (432,258)** | **$ (558,608)** | **$ (535,648)** | **$ (580,681)** | **$ (584,556)** | **$ (550,971)** | **$ (510,885)** | **$ (492,685)** | **$ (457,636)** | **$ (418,857)** | **$ (383,571)** | **$ (347,982)** | **$ (347,982)** |

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**EnergyNorth Natural Gas, Inc.**
**Energy Efficiency Programs**
**For Residential Non Heating and Heating Classes**
**November 1, 2012 - October 31, 2013**
**Energy Efficiency Charge**

| Month | Actual or Forecast | Beginning Balance (Over)/Under | Residential DSM Rate Per Therm | DSM Collections | Forecasted DSM Expenditures | Actual DSM Expenditures Residential | Actual DSM Expenditures Low-Income | Ending Balance (Over)/Under | Average Balance (Over)/Under | Interest Monthly Federal Prime Rate | Interest @ Fed Reserve Bank Loan Rate | Ending Bal. Plus Interest (Over)/Under | Forecasted Residential Therm Sales | Residential Therm Sales | # of Days |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| May 12 | Actual | (2,461,879) | ($0.0498) | (160,729) | 235,382 | 186,477 | 0 | (2,436,131) | (2,449,005) | **3.25%** | (6,760) | (2,442,891) | 4,471,593 | 3,230,081 | 31 |
| June 12 | Actual | (2,442,891) | ($0.0498) | (90,552) | 235,382 | 75,628 | 71,156 | (2,386,658) | (2,414,775) | 3.25% | (6,450) | (2,393,109) | 2,482,396 | 1,819,769 | 30 |
| July 12 | Forecast | (2,393,109) | ($0.0498) | (77,901) | 314,458 | 0 | 0 | (2,156,552) | (2,274,830) | 3.25% | (6,279) | (2,162,831) | 1,565,536 | 0 | 31 |
| August 12 | Forecast | (2,162,831) | ($0.0498) | (63,201) | 314,458 | 0 | 0 | (1,911,574) | (2,037,203) | 3.25% | (5,623) | (1,917,198) | 1,270,112 | 0 | 31 |
| September 12 | Forecast | (1,917,198) | ($0.0498) | (68,074) | 314,458 | 0 | 0 | (1,670,814) | (1,794,006) | 3.25% | (4,792) | (1,675,606) | 1,368,039 | 0 | 30 |
| October 12 | Forecast | (1,675,606) | ($0.0498) | (94,782) | 314,458 | 0 | 0 | (1,455,930) | (1,565,768) | 3.25% | (4,322) | (1,460,252) | 1,904,776 | 0 | 31 |
| November 12 | Forecast | (1,460,252) | ($0.0147) | (55,505) | 314,458 | 0 | 0 | (1,201,299) | (1,330,775) | 3.25% | (3,555) | (1,204,854) | 3,778,407 | 0 | 30 |
| December 12 | Forecast | (1,204,854) | ($0.0147) | (102,040) | 314,458 | 0 | 0 | (992,436) | (1,098,645) | 3.25% | (3,033) | (995,469) | 6,946,220 | 0 | 31 |
| January 13 | Forecast | (995,469) | ($0.0147) | (147,768) | 170,065 | 0 | 0 | (973,171) | (984,320) | 3.25% | (2,717) | (975,888) | 10,059,056 | 0 | 31 |
| February 13 | Forecast | (975,888) | ($0.0147) | (157,988) | 170,065 | 0 | 0 | (963,811) | (969,850) | 3.25% | (2,418) | (966,229) | 10,754,770 | 0 | 28 |
| March 13 | Forecast | (966,229) | ($0.0147) | (136,161) | 170,065 | 0 | 0 | (932,325) | (949,277) | 3.25% | (2,620) | (934,946) | 9,268,947 | 0 | 31 |
| April 13 | Forecast | (934,946) | ($0.0147) | (91,867) | 170,065 | 0 | 0 | (856,748) | (895,847) | 3.25% | (2,393) | (859,141) | 6,253,708 | 0 | 30 |
| May 13 | Forecast | (859,141) | ($0.0147) | (49,206) | 170,065 | 0 | 0 | (738,282) | (798,712) | 3.25% | (2,205) | (740,487) | 3,349,634 | 0 | 31 |
| June 13 | Forecast | (740,487) | ($0.0147) | (29,158) | 170,065 | 0 | 0 | (599,581) | (670,034) | 3.25% | (1,790) | (601,370) | 1,984,898 | 0 | 30 |
| July 13 | Forecast | (601,370) | ($0.0147) | (18,402) | 170,065 | 0 | 0 | (449,707) | (525,539) | 3.25% | (1,451) | (451,158) | 1,252,661 | 0 | 31 |
| August 13 | Forecast | (451,158) | ($0.0147) | (15,523) | 170,065 | 0 | 0 | (296,616) | (373,887) | 3.25% | (1,032) | (297,648) | 1,056,675 | 0 | 31 |
| September 13 | Forecast | (297,648) | ($0.0147) | (16,792) | 170,065 | 0 | 0 | (144,375) | (221,012) | 3.25% | (590) | (144,966) | 1,143,113 | 0 | 30 |
| October 13 | Forecast | (144,966) | ($0.0147) | (24,878) | 170,065 | 0 | 0 | 221 | (72,373) | 3.25% | (200) | 21 | 1,693,533 | 0 | 31 |
| November 13 | Forecast | 21 | ($0.0147) | (55,505) | 170,065 | 0 | 0 | 114,581 | 57,301 | 3.25% | 153 | 114,734 | 3,778,407 | 0 | 30 |
| December 13 | Forecast | 114,734 | ($0.0147) | (102,040) | 170,065 | 0 | 0 | 182,759 | 148,746 | 3.25% | 411 | 183,169 | 6,946,220 | 0 | 31 |

| **Estimated Residential Nonheating Conservation Charge Effective November 1, 2012 - October 31, 2013** | | |
|---|---|---|
| Beginning Balance | $ | (1,460,252) |
| Program Budget Nov 12-Oct 13 | | 2,329,562 |
| Projected Interest | | (24,003) |
| Projected Budget with Interest | $ | 845,307 |
| **Total Charges** | **$** | **845,307** |
| **Projected Therm Sales** | | **57,541,620** |
| **Residential Rate** | | **$0.0147** |
| **Total Charges with Interest** | **$** | **845,307** |
| **Projected Therm Sales** | | **57,541,620** |
| **Residential Rate** | | **$0.0147** |

| | | | | |
|---|---|---|---|---|
| Residential Non Heating Therm Sales | 1% | **1,000,804** | **861,046** | 1% |
| Residential Heating Therm Sales | 37% | **60,975,253** | **56,680,574** | 36% |
| C&I Therm Sales | 62% | **101,612,535** | **100,520,729** | 64% |
| **Total Therms** | 100% | **163,588,592** | **158,062,349** | 100% |
| | | Year One Budget | Year Two Budget | |
| | | **1/01/12 - 12/31/12** | **1/01/13 - 12/31/13** | |
| Low-Income Program Budget | | **$ 1,123,016** | **$ 750,000** | |
| Other Refund | | - | - | |
| **Total Shared Budget** | | **$ 1,123,016** | **$ 750,000** | |
| Residential Program Budget | | **$ 2,181,559** | **$ 1,620,000** | |
| Residential Program Incentive | | **$217,565** | **$147,743** | |
| **Total Residential Program Budget** | | **$ 2,399,124** | **$ 1,767,743** | |
| Commercial/Industrial Program Budget | | **$ 2,500,000** | **$ 2,310,000** | |
| Commercial/Industrial Program Incentive | | **$95,559** | **$79,168** | |
| **Total Commercial/Industrial Program Budget** | | **$ 2,595,559** | **$ 2,389,168** | |
| **Total Program Budget** | | **$ 6,117,699** | **$ 4,906,911** | |
| Shared Expenses Allocation to Residential | | $ 425,458 | $ 273,033 | |
| Shared Expenses Allocation to C&I | | 697,558 | 476,967 | |
| **Total Allocated Shared Expenses** | | **$ 1,123,016** | **$ 750,000** | |
| Total Residential (including allocation of Shared Budget) | | $ 2,824,582 | $ 2,040,776 | |
| Total C&I (including allocation of Shared Budget) | | 3,293,117 | 2,866,135 | |
| **Total Budget** | | **$ 6,117,699** | **$ 4,906,911** | |

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**EnergyNorth Natural Gas, Inc.**
**Energy Efficiency Programs**
**For Commercial/Industrial Classes**
**November 1, 2012 - October 31, 2013**
**Energy Efficiency Charge**

| Month | Actual or Forecast | Beginning Balance (Over)/Under | DSM Rate Per Therm | DSM Collections | Forecasted DSM Expenditures | Actual DSM Expenditures | | Ending Balance (Over)/Under | Average Balance (Over)/Under | Interest Fed Reserve Prime Rate | Interest @ Fed Reserve Bank Loan Rate | Ending Bal. Plus Interest (Over)/Under | Forecasted Commercial/ Industrial Therm Sales | Commercial/ Industrial Therm Sales | # of Days |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | Com-Ind | Low-Income | | | | | | | | |
| May 12 | Actual | (3,296,907) | ($0.0298) | (188,588) | 274,426 | 259,978 | 0 | (3,225,517) | (3,261,212) | **3.25%** | (9,002) | (3,234,519) | 7,675,149 | 6,328,457 | 31 |
| June 12 | Actual | (3,234,519) | ($0.0298) | (140,366) | 274,426 | 373,499 | 94,323 | (2,907,063) | (3,070,791) | 3.25% | (8,203) | (2,915,266) | 5,618,481 | 4,710,280 | 30 |
| July 12 | Forecast | (2,915,266) | ($0.0298) | (129,853) | 313,860 | 0 | 0 | (2,731,259) | (2,823,262) | 3.25% | (7,793) | (2,739,052) | 4,357,483 | 0 | 31 |
| August 12 | Forecast | (2,739,052) | ($0.0298) | (120,386) | 313,860 | 0 | 0 | (2,545,578) | (2,642,315) | 3.25% | (7,294) | (2,552,871) | 4,039,787 | 0 | 31 |
| September 12 | Forecast | (2,552,871) | ($0.0298) | (130,115) | 313,860 | 0 | 0 | (2,369,126) | (2,460,998) | 3.25% | (6,574) | (2,375,700) | 4,366,259 | 0 | 30 |
| October 12 | Forecast | (2,375,700) | ($0.0298) | (145,768) | 313,860 | 0 | 0 | (2,207,608) | (2,291,654) | 3.25% | (6,326) | (2,213,933) | 4,891,547 | 0 | 31 |
| November 12 | Forecast | (2,213,933) | ($0.0076) | (53,641) | 313,860 | 0 | 0 | (1,953,714) | (2,083,824) | 3.25% | (5,566) | (1,959,280) | 7,058,014 | 0 | 30 |
| December 12 | Forecast | (1,959,280) | ($0.0076) | (81,624) | 313,860 | 0 | 0 | (1,727,044) | (1,843,162) | 3.25% | (5,088) | (1,732,132) | 10,740,036 | 0 | 31 |
| January 13 | Forecast | (1,732,132) | ($0.0076) | (111,996) | 238,845 | 0 | 0 | (1,605,283) | (1,668,707) | 3.25% | (4,606) | (1,609,889) | 14,736,267 | 0 | 31 |
| February 13 | Forecast | (1,609,889) | ($0.0076) | (119,281) | 238,845 | 0 | 0 | (1,490,326) | (1,550,107) | 3.25% | (3,865) | (1,494,190) | 15,694,927 | 0 | 28 |
| March 13 | Forecast | (1,494,190) | ($0.0076) | (104,122) | 238,845 | 0 | 0 | (1,359,468) | (1,426,829) | 3.25% | (3,938) | (1,363,406) | 13,700,246 | 0 | 31 |
| April 13 | Forecast | (1,363,406) | ($0.0076) | (75,671) | 238,845 | 0 | 0 | (1,200,233) | (1,281,819) | 3.25% | (3,424) | (1,203,657) | 9,956,715 | 0 | 30 |
| May 13 | Forecast | (1,203,657) | ($0.0076) | (49,684) | 238,845 | 0 | 0 | (1,014,496) | (1,109,076) | 3.25% | (3,061) | (1,017,557) | 6,537,363 | 0 | 31 |
| June 13 | Forecast | (1,017,557) | ($0.0076) | (38,703) | 238,845 | 0 | 0 | (817,416) | (917,487) | 3.25% | (2,451) | (819,867) | 5,092,563 | 0 | 30 |
| July 13 | Forecast | (819,867) | ($0.0076) | (30,467) | 238,845 | 0 | 0 | (611,489) | (715,678) | 3.25% | (1,975) | (613,465) | 4,008,754 | 0 | 31 |
| August 13 | Forecast | (613,465) | ($0.0076) | (29,272) | 238,845 | 0 | 0 | (403,892) | (508,678) | 3.25% | (1,404) | (405,296) | 3,851,567 | 0 | 31 |
| September 13 | Forecast | (405,296) | ($0.0076) | (31,589) | 238,845 | 0 | 0 | (198,041) | (301,668) | 3.25% | (806) | (198,846) | 4,156,413 | 0 | 30 |
| October 13 | Forecast | (198,846) | ($0.0076) | (37,908) | 238,845 | 0 | 0 | 2,090 | (98,378) | 3.25% | (272) | 1,819 | 4,987,864 | 0 | 31 |
| November 13 | Forecast | 1,819 | ($0.0076) | (53,641) | 238,845 | 0 | 0 | 187,022 | 94,420 | 3.25% | 252 | 187,274 | 7,058,014 | 0 | 30 |
| December 13 | Forecast | 187,274 | ($0.0076) | (81,624) | 238,845 | 0 | 0 | 344,495 | 265,885 | 3.25% | 734 | 345,229 | 10,740,036 | 0 | 31 |

| **Estimated C & I Conservation Charge**<br>**Effective November 1, 2012 - October 31, 2013** | |
|---|---|
| Beginning Balance | ($2,213,933) |
| Program Budget | 3,016,166 |
| Projected Interest | (36,456) |
| Program Budget with Interest | $765,777 |
| **Total Charges** | **$765,777** |
| Projected Therm Sales | **100,520,729** |
| C&I Rate | $0.0076 |
| Total Charges with Interest | **$765,777** |
| Projected Therm Sales | **100,520,729** |
| **Com/Ind Rate** | **$0.0076** |
| Com/Ind Rate from Prior Programs (1) | **$0.0000** |
| Combined Com/Ind Rate | **$0.0076** |

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**EnergyNorth Natural Gas, Inc.**
**Energy Efficiency Programs**
**For Residential and Commercial/Industrial Classes**
**November 1, 2012 - October 31, 2013**
**Energy Efficiency Charge**

| Month | Actual or Forecast | Beginning Balance (Over)/Under | DSM Rate Per Therm | DSM Collections | Forecasted DSM Expenditures | Actual DSM Expenditures | | | | Ending Balance (Over)/Under | Average Balance (Over)/Under | Interest Plus Interest Prime Rate | Interest @ Fed Reserve Bank Loan Rate | Ending Bal. Plus Interest (Over)/Under | Forecasted Therm Sales | Therm Sales | # of Days |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | Residential | Com-Ind | Low-Income | Total | | | | | | | | |
| May 12 | Actual | (5,758,786) | n/a | (349,317) | 509,808 | 186,477 | 259,978 | 0 | 446,455 | (5,661,648) | (5,710,217) | **3.25%** | (15,762) | (5,677,409) | 12,146,742 | 9,558,538 | 31 |
| June 12 | Actual | (5,677,409) | n/a | (230,918) | 509,808 | 75,628 | 373,499 | 165,479 | 614,606 | (5,293,722) | (5,485,565) | 3.25% | (14,653) | (5,308,375) | 8,100,878 | 6,530,049 | 30 |
| July 12 | Forecast | (5,308,375) | n/a | (207,754) | 628,318 | 0 | 0 | 0 | 0 | (4,887,811) | (5,098,093) | 3.25% | (14,072) | (4,901,883) | 5,923,019 | 0 | 31 |
| August 12 | Forecast | (4,901,883) | n/a | (183,587) | 628,318 | 0 | 0 | 0 | 0 | (4,457,152) | (4,679,518) | 3.25% | (12,917) | (4,470,069) | 5,309,899 | 0 | 31 |
| September 12 | Forecast | (4,470,069) | n/a | (198,189) | 628,318 | 0 | 0 | 0 | 0 | (4,039,939) | (4,255,004) | 3.25% | (11,366) | (4,051,306) | 5,734,298 | 0 | 30 |
| October 12 | Forecast | (4,051,306) | n/a | (240,550) | 628,318 | 0 | 0 | 0 | 0 | (3,663,537) | (3,857,421) | 3.25% | (10,648) | (3,674,185) | 6,796,324 | 0 | 31 |
| November 12 | Forecast | (3,674,185) | n/a | (109,146) | 628,318 | 0 | 0 | 0 | 0 | (3,155,013) | (3,414,599) | 3.25% | (9,121) | (3,164,134) | 10,836,421 | 0 | 30 |
| December 12 | Forecast | (3,164,134) | n/a | (183,664) | 628,318 | 0 | 0 | 0 | 0 | (2,719,480) | (2,941,807) | 3.25% | (8,120) | (2,727,600) | 17,686,256 | 0 | 31 |
| January 13 | Forecast | (2,727,600) | n/a | (259,764) | 408,909 | 0 | 0 | 0 | 0 | (2,578,455) | (2,653,027) | 3.25% | (7,323) | (2,585,778) | 24,795,322 | 0 | 31 |
| February 13 | Forecast | (2,585,778) | n/a | (277,269) | 408,909 | 0 | 0 | 0 | 0 | (2,454,137) | (2,519,957) | 3.25% | (6,283) | (2,460,420) | 26,449,698 | 0 | 28 |
| March 13 | Forecast | (2,460,420) | n/a | (240,283) | 408,909 | 0 | 0 | 0 | 0 | (2,291,793) | (2,376,106) | 3.25% | (6,559) | (2,298,352) | 22,969,193 | 0 | 31 |
| April 13 | Forecast | (2,298,352) | n/a | (167,538) | 408,909 | 0 | 0 | 0 | 0 | (2,056,981) | (2,177,666) | 3.25% | (5,817) | (2,062,798) | 16,210,423 | 0 | 30 |
| May 13 | Forecast | (2,062,798) | n/a | (98,890) | 408,909 | 0 | 0 | 0 | 0 | (1,752,779) | (1,907,788) | 3.25% | (5,266) | (1,758,045) | 9,886,997 | 0 | 31 |
| June 13 | Forecast | (1,758,045) | n/a | (67,861) | 408,909 | 0 | 0 | 0 | 0 | (1,416,997) | (1,587,521) | 3.25% | (4,241) | (1,421,237) | 7,077,460 | 0 | 30 |
| July 13 | Forecast | (1,421,237) | n/a | (48,869) | 408,909 | 0 | 0 | 0 | 0 | (1,061,196) | (1,241,217) | 3.25% | (3,426) | (1,064,623) | 5,261,414 | 0 | 31 |
| August 13 | Forecast | (1,064,623) | n/a | (44,795) | 408,909 | 0 | 0 | 0 | 0 | (700,508) | (882,565) | 3.25% | (2,436) | (702,944) | 4,908,241 | 0 | 31 |
| September 13 | Forecast | (702,944) | n/a | (48,381) | 408,909 | 0 | 0 | 0 | 0 | (342,416) | (522,680) | 3.25% | (1,396) | (343,812) | 5,299,526 | 0 | 30 |
| October 13 | Forecast | (343,812) | n/a | (62,786) | 408,909 | 0 | 0 | 0 | 0 | 2,311 | (170,751) | 3.25% | (471) | 1,840 | 6,681,398 | 0 | 31 |
| November 13 | Forecast | 1,840 | n/a | (109,146) | 408,909 | 0 | 0 | 0 | 0 | 301,603 | 151,721 | 3.25% | 405 | 302,008 | 10,836,421 | 0 | 30 |
| December 13 | Forecast | 302,008 | n/a | (183,664) | 408,909 | 0 | 0 | 0 | 0 | 527,254 | 414,631 | 3.25% | 1,144 | 528,398 | 17,686,256 | 0 | 31 |

| **Residential (R-1 & R-3) and C & I Conservation Charge**<br>**Effective November 1, 2012 - October 31, 2013** | |
|---|---|
| Beginning Balance | $ (3,674,184.88) |
| Program Budget | 5,345,728.11 |
| Projected Interest | (60,459.25) |
| Program Budget with Interest | $1,611,084 |
| **Total Charges** | **$1,611,084** |

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**New Hampshire Program Year TWO (January 1, 2012 - December 31, 2012)**

| Program | Internal Admin | External Admin | Rebates/ Services | Internal Impl | Marketing | Evaluation | Budget Total | Participant Goal | Lifetime MMBTU Savings |
|---|---|---|---|---|---|---|---|---|---|
| **Residential** | | | | | | | | | |
| Low Income | $ 55,000 | $ 291,159 | $ 420,937 | | $ 5,966 | $ - | $ 1,123,016 | 275 | 75,048 |
| Residential High-Efficiency Heating, Water-Heating, Controls Program | $ 25,767 | $ 178,054 | $ 503,406 | | $ 51,087 | $ 1,425 | | 2,137 | 328,375 |
| New Home Construction with Energy Star | $ 824 | $ 32,445 | $ 51,000 | | $ 5,500 | $ - | | 34 | 23,120 |
| Res Building Practices and Demo | $ 1,556 | $ 4,523 | $ 15,000 | | $ 3,750 | $ 500 | | 10 | 0 |
| Energy Audit with Home Performance and Weatherization | $ 34,295 | $ 149,166 | $ 1,440,692 | | $ 37,623 | $ 13,631 | $ 2,181,559 | 1,400 | 394,800 |
| **Residential Total** | **$ 117,441** | **$ 655,347** | **$ 2,431,035** | **$ -** | **$ 103,926** | **$ 15,556** | **$ 3,304,575** | **3,856** | **821,343** |
| **Commercial & Industrial** | | | | | | | | | |
| Large C & I Retrofit Program | $ 176,000 | $ 165,000 | $ 1,567,500 | | $ 64,488 | $ 68,936 | | 270 | 769,785 |
| New Equipment and Construction Program | $ 104,500 | $ 110,000 | $ 841,500 | | $ 38,363 | $ 41,008 | | 371 | 314,735 |
| Small Business Energy Solutions Program | $ 32,240 | $ 48,360 | $ 253,125 | | $ 10,284 | $ 12,493 | | 29 | 141,071 |
| **Commercial Total** | **$ 312,740** | **$ 323,360** | **$ 2,662,125** | **$ -** | **$ 113,134** | **$ 122,437** | **$ 2,500,000** | **670** | **1,225,591** |
| **GRAND TOTAL** | **$ 430,181** | **$ 978,707** | **$ 5,093,160** | **$ -** | **$ 217,060** | **$ 137,993** | **$ 5,804,575** | **4,526** | **2,046,934** |

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**New Hampshire Program Year TWO (January 1, 2013 - December 31, 2013)**

| Program | Internal Admin | External Admin | Rebates/ Services | Internal Impl | Marketing | Evaluation | Budget Total | Participant Goal | Lifetime MMBTU Savings |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | |
| **Residential** | | | | | | | | | |
| Low Income | $ - | $ - | $ - | | $ - | $ - | $ 750,000 | 0 | 0 |
| High-Efficiency Heating, Water-Heating, Controls Program | $ - | $ - | $ - | | $ - | $ - | $ 730,000 | 0 | 0 |
| New Home Construction with Energy Star | $ - | $ - | $ - | | $ - | $ - | $ 90,000 | 0 | 0 |
| Building Practices and Demo | $ - | $ - | $ - | | $ - | $ - | $ 70,000 | 0 | 0 |
| Home Performance w/Energy Star | $ - | $ - | $ - | | $ - | $ - | $ 730,000 | 0 | 0 |
| | | | | | | | | | |
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| | | | | | | | | | |
| **Residential Total** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ 2,370,000** | **0** | **0** |
| | | | | | | | | | |
| **Commercial & Industrial** | | | | | | | | | |
| Large Business | $ - | $ - | $ - | | $ - | $ - | $ 950,000 | 0 | 0 |
| New Equipment and Construction Program | $ - | $ - | $ - | | $ - | $ - | $ - | 0 | 0 |
| Small Business | $ - | $ - | $ - | | $ - | $ - | $ 1,360,000 | 0 | 0 |
| | | | | | | | | | |
| | | | | | | | | | |
| | | | | | | | | | |
| | | | | | | | | | |
| **Commercial Total** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ 2,310,000** | **0** | **0** |
| | | | | | | | | | |
| **GRAND TOTAL** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ 4,680,000** | **0** | **0** |

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# Exhibit D - Shareholder Incentive Page 1 of 1

## National Grid Gas Energy Efficiency

### Shareholder Incentive Year TWO- January 1, 2010 - December 31, 2010

**Commercial/Industrial Incentive**

| | | |
|---|---|---|
| 1. | Target Benefit/Cost Ratio | 2.01 |
| | Actual Benefit/Cost Ratio | 1.99 |
| 2. | Threshold Benefit/Cost Ratio | 1.00 |
| 3. | Target lifetime MMBTU | 1,236,404 |
| | Actual lifetime MMBTU | 678,145 |
| 4. | Threshold MMBTU | 803,663 |
| 5. | Budget | $2,411,290 |
| 6. | CE Percentage | 4.00% |
| 7. | Lifetime MMBTU Percentage | 4.00% |
| **8.** | **Target C/I Incentive** | **$192,903** |
| | **Actual C/I Incentive** | **$95,559** |
| **9.** | **Cap** | **$289,355** |

**Residential Incentive**

| | | |
|---|---|---|
| 10. | Target Benefit/Cost Ratio | 2.15 |
| | Actual Benefit/Cost Ratio | 2.54 |
| 11. | Threshold Benefit/Cost Ratio | 1.00 |
| 12. | Target lifetime MMBTU | 885,455 |
| | Actual Lifetime MMBTU | 821,512 |
| 13. | Threshold MMBTU | 575,546 |
| 14. | Budget | $2,575,126 |
| 15. | CE Percentage | 4.00% |
| 16. | Lifetime MMBTU Percentage | 4.00% |
| **17.** | **Target Residential Incentive** | **$206,010** |
| | **Actual Residential Incentive** | **$217,565** |
| **18.** | **Cap** | **$309,015** |
| **19.** | **TOTAL TARGET INCENTIVE** | **$313,124** |

# Exhibit B - Shareholder Incentive Page 1 of 2

## National Grid NH Energy Efficiency

Target Shareholder Incentive Year ONE- January 1, 2011 - December 31, 2011

| **Commercial/Industrial Incentive** | **Planned** | **Actual** |
|---|---|---|
| 1. Benefit/Cost Ratio | 1.47 | 2.35 |
| 2. Threshold Benefit / Cost Ratio [1] | 1.00 | |
| 3. Lifetime MMBTU Savings | 1,091,292 | 702,108 |
| 4. Threshold Lifetime MMBTU Savings (65%) [2] | 709,340 | |
| 5. Budget / Actual Spend | $3,174,772 | $1,242,485 |
| 6. Benefit / Cost Percentage of Budget | 4.00% | |
| 7. Lifetime MMBTU Percentage of Budget | 4.00% | |
| **8. C/I Incentive** | **$253,982** | **$79,168** |
| **9. Cap** | **$380,973** | |
| **Residential Incentive** | | |
| 10. Benefit / Cost Ratio | 1.96 | 1.68 |
| 11. Threshold Benefit / Cost Ratio [1] | 1.00 | |
| 12. Lifetime MMBTU Savings | 736,594 | 555,567 |
| 13. Threshold Lifetime MMBTU Savings (65%) [2] | 478,786 | |
| 14. Budget / Actual Spend | $3,090,674 | $2,286,081 |
| 15. Benefit / Cost Percentage of Budget | 4.00% | |
| 16. Lifetime MMBTU Percentage of Budget | 4.00% | |
| **17. Residential Incentive** | **$247,254** | **$147,743** |
| **18. Cap** | **$370,881** | |
| **19. TOTAL INCENTIVE** | **$501,236** | **$226,911** |

**NHPUC NO. 7 - GAS**
**LIBERTY UTILITIES**

**Environmental Surcharge - Manufactured Gas Plants**

**Manufactured Gas Plants**

| | | |
|---|---|---|
| Required annual Environmental increase | $256,547 | |
| DG 10-17 Base Rate Revision Collections | ($78,892) | |
| Environmental Subtotal | $177,655 | |
| Overall Annual Net Increase to Rates | $177,655 | |
| Estimated weather normalized firm therms billed for the twelve months ended 10/31/13 - sales and transportation | 158,062,349 | therms |
| Surcharge per therm | $0.0011 | per therm |
| **Total Environmental Surcharge** | $0.0011 | |

**Filed under the following protective orders:**
**Order No. 22,853 dated February 18, 1998 in Docket No. DR 97-130**
**Order No. 23,316 dated October 11, 1999 in Docket No. DG 99-132**

**EnergyNorth Natural Gas, Inc.**
**Environmental Remediation - MGPs**
**Tariff page 91**

**Concord Pond**

**internal order no. 500061 (formerly acc no. 1796)**

| | | (thru 3/98) pool #1 | (4/98 - 9/98) pool #2 | (10/98 - 9/15/99) pool #3 | (9/99 - 9/00) pool #4 | (9/03 - 9/04) pool #5 | (9/04 - 9/05) pool #6 | (9/05 - 9/06) pool #7 | (9/06 - 9/07) pool #8 | (9/07 - 9/08) pool #9 | (9/08 - 9/09) pool #10 | (9/09 - 9/10) pool #11 | (9/10 - 9/11) pool #11 | (9/11 - 9/12) pool #12 | subtotal |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 1 Remediation costs (i.o. 500061) | 1,422,811 | 1,843,806 | 2,154,235 | 129,002 | 60,293 | 21,613 | 96,293 | 155,796 | 95,374 | 128,187 | 143,000 | 249,448 | 86,412 | 6,586,270 |
| 2 | Remediation costs (i.o. 500005) | - | - | - | - | | | | | | | | | | - |
| 3 | A Subtotal - remediation costs | 1,422,811 | 1,843,806 | 2,154,235 | 129,002 | 60,293 | 21,613 | 96,293 | 155,796 | 95,374 | 128,187 | 143,000 | 249,448 | 86,412 | 6,586,270 |
| 4 | | | | | | | | | | | | | | | - |
| 5 | Cash recoveries (i.o. 500061) | (1,080,580) | (434,476) | (499,684) | (33,204) | | | (14,314) | (13,446) | - | (12,608) | (6,064) | (32,417) | (5,173) | (2,131,966) |
| 6 | Cash recoveries (i.o. 500004) | (445,985) | - | - | - | | | | | | | | | | (445,985) |
| 7 | Recovery costs (i.o. 500004) | 623,784 | - | - | - | | | | - | - | - | - | - | - | 623,784 |
| 8 | Transfer Credit from Gas Restructuring | | | | | | | | | | | | | | - |
| 9 | B Subtotal - net recoveries | (902,781) | (434,476) | (499,684) | (33,204) | - | - | (14,314) | (13,446) | - | (12,608) | (6,064) | (32,417) | (5,173) | (1,954,167) |
| 10 | | | | | | | | | | | | | | | - |
| 11 | A-B Total net expenses to recover | 520,030 | 1,409,330 | 1,654,552 | 95,798 | 60,293 | 21,613 | 81,979 | 142,350 | 95,374 | 115,579 | 136,936 | 217,032 | 81,238 | 4,632,103 |
| 12 | | | | | | | | | | | | | | | - |
| 13 | | | | | | | | | | | | | | | - |
| 14 | Surcharge revenue: | | | | | | | | | | | | | | - |
| 15 | Act June 1998 - October 1998 | (54,889) | - | - | - | | | | | | | | | | (54,889) |
| 16 | Act November 1998 - October 1999 | (287,010) | (251,133) | - | - | | | | | | | | | | (538,143) |
| 17 | Act November 1999 - October 2000 | (178,131) | (266,400) | (316,340) | - | | | | | | | | | | (760,871) |
| 18 | Act November 2000 - October 2001 | - | (292,420) | (334,194) | (13,925) | | | | | | | | | | (640,539) |
| 19 | Act November 2001 - October 2002 | - | (281,914) | (318,686) | (24,514) | | | | | | | | | | (625,114) |
| 20 | Act November 2002 - October 2003 | - | (258,347) | (334,331) | (15,197) | | | | | | | | | | (607,874) |
| 21 | Act November 2003 - October 2004 | - | (14,567) | (276,773) | (14,567) | | | | | | | | | | (305,907) |
| 22 | Act November 2004- October 2005 | - | - | (56,719) | (14,180) | (14,180) | | | | | | | | | (85,078) |
| 23 | Act November 2005- October 2006 | - | - | - | (6,875) | (6,875) | | | | | | | | | (13,750) |
| 24 | Act November 2006- October 2007 | - | - | - | - | - | - | (14,091) | | | | | | | (14,091) |
| 25 | Act November 2007- October 2008 | | | | | | | | | | | | | | - |
| 26 | Act Nov 2009-Oct 2010 Base Rate Rev | | | | | | | | | | | | ($4,416) | | (4,416) |
| 27 | Act Nov 2010-Oct 2011 Base Rate Rev | | | | | | | | | | | | ($32,261) | | (32,261) |
| 28 | Act Nov 2011-Oct 2012 Base Rate Rev | | | | | | | | | | | | ($28,308) | | (28,308) |
| 29 | AES collections | | | | | (33,593) | (11,626) | (11,901) | (12,271) | (12,620) | (12,904) | (13,145) | (13,221) | (13,429) | (134,711) |
| 30 | Gas Street overcollection | - | (23,511) | | | | | | | | | | | | (23,511) |
| 31 | Prior Period Pool under/overcollection | | - | 21,038 | 38,548 | 45,088 | 50,734 | 60,721 | 116,708 | 246,787 | - | - | - | - | |
| 32 | | | | | | | | | | | | | | | 0 |
| 33 | | | | | | | | | | | | | | | - |
| 34 | C Surcharge Subtotal | (520,030) | (1,388,292) | (1,616,004) | (50,710) | (9,559) | 39,108 | 34,729 | 104,437 | 234,166 | (12,904) | (13,145) | (78,205) | (13,429) | (3,869,461) |
| 35 | | | | | | | | | | | | | | | |
| 36 | | | | | | | | | | | | | | | |
| 37 | D Net balance to be recovered (A-B+C) | - | 21,038 | 38,548 | 45,088 | 50,734 | 60,721 | 116,708 | 246,787 | 329,540 | 102,675 | 123,791 | 138,826 | 67,810 | 762,642 |
| 38 | | | | | | | | | | | | | | | |
| 39 | E Allocation of Litigated Recovery | | | | | - | | - | | (329,540) | (102,675) | (123,791) | (67,710) | - | (623,716) |
| 40 | | | | | | | | | | | | | | | |
| 41 | Surcharge calculation 2007/2008 | | | | | | | | | | | | | | |
| 42 | Unrecovered costs (D+E) | - | - | - | - | - | - | - | - | - | - | - | 71,116 | 67,810 | 138,926 |
| 43 | remaining life | - | - | - | - | 24 | 36 | 48 | 60 | 72 | 84 | 84 | 72 | 84 | |
| 44 | one year | - | - | - | - | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | |
| 45 | F amortization 2007/2008 | - | - | - | - | - | - | - | | - | - | - | 11,853 | 9,687 | 21,540 |
| 46 | | | | | | | | | | | | | | | |
| 47 | Required annual increase in rates 2007/2008: | | | | | | | | | | | | | | |
| 48 | smaller of D or F | - | - | - | - | - | - | - | | - | - | - | 11,853 | 9,687 | 21,540 |
| 49 | | | | | | | | | | | | | | | |
| 50 | forecasted therm sales | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 |
| 51 | | | | | | | | | | | | | | | |
| 52 | surcharge per therm | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0001 | $0.0001 | $0.0001 |

1. While the recoveries are displayed on the Summary, Cash Recoveries by site, are not exclusive to a particular site.

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**Filed under the following protective orders:**
**Order No. 22,853 dated February 18, 1998 in Docket No. DR 97-130**
**Order No. 23,316 dated October 11, 1999 in Docket No. DG 99-132**

**EnergyNorth Natural Gas, Inc.**
**Environmental Remediation - MGPs**
**Tariff page 91**

**Laconia & Liberty Hill**

| | | i.o. no. 500005 (through 9/15/99) pool #1 | (9/99 - 9/00) pool #2 | (9/00 - 9/01) pool #3 | (9/04 - 9/05) pool #4 | (9/05 - 9/06) pool #5 | (9/06 - 9/07) pool #6 | (9/07 - 9/08) pool #7 Incl. Audit Corr | (9/08 - 9/09) pool #8 Incl. Audit Corr | (9/09 - 9/10) pool #9 | (9/10 - 9/11) pool #10 | (9/11 - 9/12) pool #11 | subtotal |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 1 Remediation costs (i.o. 500061) | - | - | | - | | | | | | | | - |
| 2 | Remediation costs (i.o. 500005) | 1,027,747 | 3,513,285 | 700,000 | 9,702 | 2,330,555 | 2,089,199 | 428,225 | 607,876 | 262,678 | 211,728 | 269,281 | 11,450,276 |
| 3 | A Subtotal - remediation costs | 1,027,747 | 3,513,285 | 700,000 | 9,702 | 2,330,555 | 2,089,199 | 428,225 | 607,876 | 262,678 | 211,728 | 269,281 | 11,450,276 |
| 4 | | | | | | | | | | | | | |
| 5 | Cash recoveries (i.o. 500061) | - | - | - | - | - | - | - | - | | | | - |
| 6 | Cash recoveries (i.o. 500004) | - | - | - | - | - | - | - | - | | | | - |
| 7 | Recovery costs (i.o. 500004) | - | - | - | | | 11,643 | 21,729 | - | - | | | 33,372 |
| 8 | Transfer Credit from Gas Restructuring | | | | | | - | - | - | | | | - |
| 9 | B Subtotal - net recoveries | - | - | - | - | - | 11,643 | 21,729 | - | - | - | - | 33,372 |
| 10 | | | | | | | | | | | | | |
| 11 | A-B Total net expenses to recover | 1,027,747 | 3,513,285 | 700,000 | 9,702 | 2,330,555 | 2,100,842 | 449,954 | 607,876 | 262,678 | 211,728 | 269,281 | 11,483,648 |
| 12 | | | | | | | | | | | | | |
| 13 | | | | | | | | | | | | | |
| 14 | Surcharge revenue: | | | | | | | | | | | | |
| 15 | Act June 1998 - October 1998 | - | - | - | - | - | | - | - | - | - | - | - |
| 16 | Act November 1998 - October 1999 | - | - | - | - | - | | - | - | - | - | - | - |
| 17 | Act November 1999 - October 2000 | (151,933) | - | - | - | - | | - | - | - | - | - | (151,933) |
| 18 | Act November 2000 - October 2001 | (153,172) | (543,065) | - | - | - | | - | - | - | - | - | (696,237) |
| 19 | Act November 2001 - October 2002 | (159,343) | (527,057) | (110,314) | - | - | | - | - | - | - | - | (796,714) |
| 20 | Act November 2002 - October 2003 | (151,969) | (547,087) | (106,378) | - | - | | - | - | - | - | - | (805,434) |
| 21 | Act November 2003 - October 2004 | (131,103) | (466,143) | (101,969) | | | | | | | | | (699,215) |
| 22 | Act November 2004- October 2005 | (127,617) | (439,570) | (85,078) | | | | | | | | | (652,264) |
| 23 | Act November 2005- October 2006 | (141,176) | (453,736) | (96,247) | - | - | | - | - | - | - | - | (691,159) |
| 24 | Act November 2006- October 2007 | - | (549,539) | (98,635) | - | (309,996) | | | | | | | (958,171) |
| 25 | Act November 2007- October 2008 | | | | | | | | | | | | - |
| 26 | Act Nov 2009-Oct 2010 Base Rate Rev | | | | | | | | | | ($4,308) | | (4,308) |
| 27 | Act Nov 2010-Oct 2011 Base Rate Rev | | | | | | | | | | ($31,472) | | (31,472) |
| 28 | Act Nov 2011-Oct 2012 Base Rate Rev | | | | | | | | | | ($27,616) | | (27,616) |
| 29 | AES collections | | | | | | | | | | | | - |
| 30 | Gas Street overcollection | | | | | | | | | | | | - |
| 31 | Prior Period Pool under/overcollection | | 11,434 | (1,477) | 99,902 | 109,604 | 2,130,162 | 4,231,004 | | - | - | (18,523) | |
| 32 | | | | | | | | | | | | | |
| 33 | | | | | | | | | | | | | |
| 34 | C Surcharge Subtotal | (1,016,313) | (3,514,762) | (600,098) | 99,902 | (200,393) | 2,130,162 | 4,231,004 | - | - | (63,396) | (18,523) | (5,514,523) |
| 35 | | | | | | | | | | | | | |
| 36 | | | | | | | | | | | | | |
| 37 | D Net balance to be recovered (A-B+C) | 11,434 | (1,477) | 99,902 | 109,604 | 2,130,162 | 4,231,004 | 4,680,958 | 607,876 | 262,678 | 148,331 | 250,758 | 5,969,125 |
| 38 | | | | | | | | | | | | | |
| 39 | E Allocation of Litigated Recovery | | | | | | | (4,680,958) | (607,876) | (262,678) | (166,854) | - | (5,718,366) |
| 40 | | | | | | | | | | | | | |
| 41 | Surcharge calculation 2007/2008 | | | | | | | | | | | | |
| 42 | Unrecovered costs (D+E) | - | - | - | - | | | - | - | - | (18,523) | 250,758 | 232,236 |
| 43 | remaining life | - | - | - | 36 | 48 | 60 | 72 | 84 | 84 | 72 | 84 | |
| 44 | one year | - | - | - | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | |
| 45 | F amortization 2007/2008 | - | - | - | - | - | - | - | - | - | - | 35,823 | 35,823 |
| 46 | | | | | | | | | | | | | |
| 47 | Required annual increase in rates 2007/2 | | | | | | | | | | | | |
| 48 | smaller of D or F | - | - | - | - | - | | - | - | - | - | 35,823 | 35,823 |
| 49 | | | | | | | | | | | | | |
| 50 | forecasted therm sales | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 |
| 51 | | | | | | | | | | | | | |
| 52 | surcharge per therm | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0002 | $0.0002 |

1. While the recoveries are displayed on the Summary, Cash Recoveries by site, are not exclusive to a particular site.

**Filed under the following protective orders:**
**Order No. 22,853 dated February 18, 1998 in Docket No. DR 97-130**
**Order No. 23,316 dated October 11, 1999 in Docket No. DG 99-132**

**EnergyNorth Natural Gas, Inc.**
**Environmental Remediation - MGPs**
**Tariff page 91**

**Manchester**

| | | (9/00 - 9/01) pool #1 | (9/02 - 9/03) pool #2 | (9/02 - 9/03) pool #3 (withdrawn 2/1/04) | (9/03 - 9/04) pool #4 | (9/04 - 9/05) pool #5 | (9/05 - 9/06) pool #6 | (9/06 - 9/07) pool #7 | (9/07 - 9/08) pool #8 Incl. Audit Corr | (9/08 - 9/09) pool #9 | (9/09 - 9/10) pool #10 | (9/10 - 9/11) pool #11 | (9/11 - 9/12) pool #12 | subtotal |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 1 Remediation costs (i.o. 500061) | - | - | | 335,338 | 1,989,848 | 875,702 | 561,210 | 4,387,645 | 312,185 | 369,037 | 372,281 | 507,622 | 9,710,868 |
| 2 | Remediation costs (i.o. 500005) | 495,106 | 329,986 | | | | | | | | | | | 825,092 |
| 3 | A Subtotal - remediation costs | 495,106 | 329,986 | - | 335,338 | 1,989,848 | 875,702 | 561,210 | 4,387,645 | 312,185 | 369,037 | 372,281 | 507,622 | 10,535,960 |
| 4 | | | | | | | | | | | | | | |
| 5 | Cash recoveries (i.o. 500061) | - | - | | | | (545,540) | (220,353) | (1,127,436) | | (40,359) | (234,648) | (65,324) | (2,233,660) |
| 6 | Cash recoveries (i.o. 500004) | - | - | | | | | | | | | | | - |
| 7 | Recovery costs (i.o. 500004) | - | - | | 1,242,326 | | | 2,546 | - | | | | | 1,244,872 |
| 8 | Transfer Credit from Gas Restructuring | | | | | | | - | - | | | | | - |
| 9 | B Subtotal - net recoveries | - | - | - | 1,242,326 | - | (545,540) | (217,807) | (1,127,436) | - | (40,359) | (234,648) | (65,324) | (988,788) |
| 10 | | | | | | | | | | | | | | |
| 11 | A-B Total net expenses to recover | 495,106 | 329,986 | - | 1,577,664 | 1,989,848 | 330,162 | 343,402 | 3,260,209 | 312,185 | 328,678 | 137,633 | 442,298 | 9,547,172 |
| 12 | | | | | | | | | | | | | | - |
| 13 | | | | | | | | | | | | | | - |
| 14 | Surcharge revenue: | | | | | | | | | | | | | - |
| 15 | Act June 1998 - October 1998 | - | - | - | - | | | | | | | | | - |
| 16 | Act November 1998 - October 1999 | - | - | - | - | | | | | | | | | - |
| 17 | Act November 1999 - October 2000 | - | - | - | - | | | | | | | | | - |
| 18 | Act November 2000 - October 2001 | - | - | - | - | | | | | | | | | - |
| 19 | Act November 2001 - October 2002 | (73,543) | - | - | - | | | | | | | | | (73,543) |
| 20 | Act November 2002 - October 2003 | (75,984) | - | - | - | | | | | | | | | (75,984) |
| 21 | Act November 2003 - October 2004 | (72,835) | (24,416) | (41,325) | - | | | | | | | | | (138,576) |
| 22 | Act November 2004- October 2005 | (70,898) | (42,539) | - | (212,695) | - | | | - | - | - | - | - | (326,132) |
| 23 | Act November 2005- October 2006 | (54,998) | (41,249) | - | (206,243) | (261,242) | | | - | - | - | - | - | (563,732) |
| 24 | Act November 2006- October 2007 | (70,454) | (56,363) | - | (211,361) | (281,815) | (42,272) | | | | | | | (662,265) |
| 25 | Act November 2007- October 2008 | | | | | | | | | | | | | - |
| 26 | Act Nov 2009-Oct 2010 Base Rate Rev | | | | | | | | | | | $0 | | - |
| 27 | Act Nov 2010-Oct 2011 Base Rate Rev | | | | | | | | | | | $0 | | - |
| 28 | Act Nov 2011-Oct 2012 Base Rate Rev | | | | | | | | | | | $0 | | - |
| 29 | AES collections | | | | | | | | | | | | | - |
| 30 | Gas Street overcollection | | | | | | | | | | | | | - |
| 31 | Prior Period Pool under/overcollection | | 76,393 | 241,813 | 200,488 | 1,147,852 | 2,594,644 | 2,882,534 | 3,225,936 | - | - | - | | |
| 32 | | | | | | | | | | | | | | |
| 33 | | | | | | | | | | | | | | |
| 34 | C Surcharge Subtotal | (418,713) | (88,173) | 200,488 | (429,812) | 604,796 | 2,552,371 | 2,882,534 | 3,225,936 | - | - | - | - | (1,840,233) |
| 35 | | | | | | | | | | | | | | |
| 36 | | | | | | | | | | | | | | |
| 37 | D Net balance to be recovered (A-B+C) | 76,393 | 241,813 | 200,488 | 1,147,852 | 2,594,644 | 2,882,534 | 3,225,936 | 6,486,145 | 312,185 | 328,678 | 137,633 | 442,298 | 7,706,939 |
| 38 | | | | | | | | | | | | | | |
| 39 | E Allocation of Litigated Recovery | | | - | - | - | | | (6,486,145) | (312,185) | (328,678) | (135,468) | - | (7,262,476) |
| 40 | | | | | | | | | | | | | | |
| 41 | Surcharge calculation 2007/2008 | | | | | | | | | | | | | |
| 42 | Unrecovered costs (D+E) | - | - | - | - | - | - | | - | - | - | 2,166 | 442,298 | 444,463 |
| 43 | remaining life | - | - | - | 24 | 36 | 48 | 60 | 70 | 84 | 84 | 72 | 84 | |
| 44 | one year | - | - | - | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | |
| 45 | F amortization 2007/2008 | - | - | - | - | - | - | - | - | - | - | 361 | 63,185 | |
| 46 | | | | | | | | | | | | | | |
| 47 | Required annual increase in rates 2007/2 | | | | | | | | | | | | | |
| 48 | smaller of D or F | - | - | - | - | - | - | | - | - | - | 361 | 63,185 | 63,546 |
| 49 | | | | | | | | | | | | | | |
| 50 | forecasted therm sales | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 |
| 51 | | | | | | | | | | | | | | |
| 52 | surcharge per therm | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0004 | $0.0004 |

1. While the recoveries are displayed on the Summary, Cash Recoveries by site, are not exclusive to a particular site.

00000185

**Filed under the following protective orders:**
**Order No. 22,853 dated February 18, 1998 in Docket No. DR 97-130**
**Order No. 23,316 dated October 11, 1999 in Docket No. DG 99-132**

**EnergyNorth Natural Gas, Inc.**
**Environmental Remediation - MGPs**
**Tariff page 91**

| | | Nashua | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (9/00 - 9/01) pool #1 | (9/01 - 9/02) pool #2 | (9/02 - 9/03) pool #3 | (9/03 - 9/04) pool #4 | (9/04 - 9/05) pool #5 | (9/05 - 9/06) pool #6 | Corrected per 2/08 Audit (9/06 - 9/07) pool #7 | (9/07 - 9/08) pool #8 | (9/08 - 9/09) pool #9 | (9/09 - 9/10) pool #9 | (9/10 - 9/11) pool #10 | (9/11 - 9/12) pool #11 | subtotal |
| 1 | 1 Remediation costs (i.o. 500061) | - | - | - | 10,841 | 206,367 | 23,354 | 9,737 | 107,605 | 78,535 | 162,729 | 65,166 | 399,400 | 1,063,734 |
| 2 | Remediation costs (i.o. 500005) | 1,233,726 | 362,663 | 175,178 | | | | | | | | | | 1,771,567 |
| 3 | A Subtotal - remediation costs | 1,233,726 | 362,663 | 175,178 | 10,841 | 206,367 | 23,354 | 9,737 | 107,605 | 78,535 | 162,729 | 65,166 | 399,400 | 2,835,300 |
| 4 | | | | | | | | | | | | | | - |
| 5 | Cash recoveries (i.o. 500061) | - | - | - | | | (18,581) | (4,151) | (10,414) | (62,246) | (63,753) | (31,767) | (2,990) | (193,902) |
| 6 | Cash recoveries (i.o. 500004) | - | - | - | | | | | | | | | | - |
| 7 | Recovery costs (i.o. 500004) | - | - | - | | | 5,449 | 12,938 | - | - | | | | 18,388 |
| 8 | Transfer Credit from Gas Restructuring | | | | | | | - | - | - | | | | - |
| 9 | B Subtotal - net recoveries | - | - | - | - | | (13,131) | 8,787 | (10,414) | (62,246) | (63,753) | (31,767) | (2,990) | (175,515) |
| 10 | | | | | | | | | | | | | | - |
| 11 | A-B Total net expenses to recover | 1,233,726 | 362,663 | 175,178 | 10,841 | 206,367 | 10,223 | 18,524 | 97,191 | 16,289 | 98,975 | 33,399 | 396,411 | 2,659,786 |
| 12 | | | | | | | | | | | | | | |
| 13 | | | | | | | | | | | | | | |
| 14 | Surcharge revenue: | | | | | | | | | | | | | |
| 15 | Act June 1998 - October 1998 | - | - | - | - | | | | | | | | | - |
| 16 | Act November 1998 - October 1999 | - | - | - | - | | | | | | | | | - |
| 17 | Act November 1999 - October 2000 | - | - | - | - | | | | | | | | | - |
| 18 | Act November 2000 - October 2001 | - | - | - | - | | | | | | | | | - |
| 19 | Act November 2001 - October 2002 | (183,857) | - | - | - | | | | | | | | | (183,857) |
| 20 | Act November 2002 - October 2003 | (182,362) | (60,787) | - | - | | | | | | | | | (243,150) |
| 21 | Act November 2003 - October 2004 | (174,804) | (43,701) | (29,134) | - | | | | | | | | | (247,639) |
| 22 | Act November 2004- October 2005 | (170,156) | (42,539) | (28,359) | - | | | | | | | | | (241,054) |
| 23 | Act November 2005- October 2006 | (164,995) | (54,998) | (27,499) | - | (27,499) | | | - | - | - | - | - | (274,991) |
| 24 | Act November 2006- October 2007 | (169,089) | (56,363) | (28,181) | - | (28,181) | - | | | | | | | (281,815) |
| 25 | Act November 2007- October 2008 | | | | | | | | | | | | | - |
| 26 | Act Nov 2009-Oct 2010 Base Rate Rev | | | | | | | | | | | $0 | | - |
| 27 | Act Nov 2010-Oct 2011 Base Rate Rev | | | | | | | | | | | $0 | | - |
| 28 | Act Nov 2011-Oct 2012 Base Rate Rev | | | | | | | | | | | $0 | | - |
| 29 | AES collections | | | | | | | | | | | | | - |
| 30 | Gas Street overcollection | | | | | | | | | | | | | - |
| 31 | Prior Period Pool under/overcollection | | 188,463 | 292,737 | 354,741 | 365,582 | 516,269 | 526,492 | 545,015 | - | - | - | (277) | |
| 32 | | | | | | | | | | | | | | |
| 33 | | | | | | | | | | | | | | |
| 34 | C Surcharge Subtotal | (1,045,263) | (69,925) | 179,564 | 354,741 | 309,902 | 516,269 | 526,492 | 545,015 | - | - | - | (277) | (1,472,506) |
| 35 | | | | | | | | | | | | | | |
| 36 | | | | | | | | | | | | | | |
| 37 | D Net balance to be recovered (A-B+C) | 188,463 | 292,737 | 354,741 | 365,582 | 516,269 | 526,492 | 545,015 | 642,206 | 16,289 | 98,975 | 33,399 | 396,134 | 1,187,280 |
| 38 | | | | | | | | | | | | | | |
| 39 | E Allocation of Litigated Recovery | - | - | - | - | - | - | - | (642,206) | (16,289) | (98,975) | (33,676) | - | (791,146) |
| 40 | | | | | | | | | | | | | | |
| 41 | Surcharge calculation 2007/2008 | | | | | | | | | | | | | |
| 42 | Unrecovered costs (D+E) | - | - | - | - | - | - | | - | - | - | | 396,134 | 396,134 |
| 43 | remaining life | - | - | 12 | 24 | 36 | 48 | 60 | 72 | 84 | 84 | 72 | 84 | |
| 44 | one year | - | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | |
| 45 | F amortization 2007/2008 | - | - | - | - | - | - | - | - | - | - | - | 56,591 | |
| 46 | | | | | | | | | | | | | | |
| 47 | Required annual increase in rates 2007/2 | | | | | | | | | | | | | |
| 48 | smaller of D or F | - | - | - | - | - | - | | - | - | - | - | 56,591 | 56,591 |
| 49 | | | | | | | | | | | | | | |
| 50 | forecasted therm sales | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 |
| 51 | | | | | | | | | | | | | | |
| 52 | surcharge per therm | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0004 | $0.0004 |

1. While the recoveries are displayed on the Summary, Cash Recoveries by site, are not exclusive to a particular site.

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**Filed under the following protective orders:**
**Order No. 22,853 dated February 18, 1998 in Docket No. DR 97-130**
**Order No. 23,316 dated October 11, 1999 in Docket No. DG 99-132**

**EnergyNorth Natural Gas, Inc.**
**Environmental Remediation - MGPs**
**Tariff page 91**

| | | Dover | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (9/02 - 9/03) pool #1 | (9/04 - 9/05) pool #2 | (9/05 - 9/06) pool #3 | (9/06 - 9/07) pool #4 | (9/07 - 9/08) pool #5 | (9/08 - 9/09) pool #6 | (9/09 - 9/10) pool #7 | (9/10 - 9/11) pool #8 | (9/11 - 9/12) pool #9 | subtotal |
| 1 | 1 Remediation costs (i.o. 500061) | - | 18,854 | 2,288 | - | - | - | - | - | - | 21,142 |
| 2 | Remediation costs (i.o. 500005) | 181,066 | | | | | | | | | 181,066 |
| 3 | A Subtotal - remediation costs | 181,066 | 18,854 | 2,288 | - | - | - | - | - | - | 202,208 |
| 4 | | | | | | | | | | | |
| 5 | Cash recoveries (i.o. 500061) | - | | | | | - | - | - | - | - |
| 6 | Cash recoveries (i.o. 500004) | - | | | | | | | | | - |
| 7 | Recovery costs (i.o. 500004) | - | | | | | | | | | - |
| 8 | Transfer Credit from Gas Restructuring | | | | | | | | | | - |
| 9 | B Subtotal - net recoveries | - | - | - | - | - | - | - | - | - | - |
| 10 | | | | | | | | | | | |
| 11 | A-B Total net expenses to recover | 181,066 | 18,854 | 2,288 | - | - | - | - | - | - | 202,208 |
| 12 | | | | | | | | | | | |
| 13 | | | | | | | | | | | |
| 14 | Surcharge revenue: | | | | | | | | | | |
| 15 | Act June 1998 - October 1998 | - | | | | | | | | | - |
| 16 | Act November 1998 - October 1999 | - | | | | | | | | | - |
| 17 | Act November 1999 - October 2000 | - | | | | | | | | | - |
| 18 | Act November 2000 - October 2001 | - | | | | | | | | | - |
| 19 | Act November 2001 - October 2002 | - | | | | | | | | | - |
| 20 | Act November 2002 - October 2003 | - | | | | | | | | | - |
| 21 | Act November 2003 - October 2004 | (29,134) | | | | | | | | | (29,134) |
| 22 | Act November 2004- October 2005 | (28,359) | | | | | | | | | (28,359) |
| 23 | Act November 2005- October 2006 | (27,499) | - | | | - | - | - | - | - | (27,499) |
| 24 | Act November 2006- October 2007 | (28,181) | - | - | | | | | | | (28,181) |
| 25 | Act November 2007- October 2008 | | | | | | | | | | - |
| 26 | Act Nov 2009-Oct 2010 Base Rate Rev | | | | | | | | | | |
| 27 | Act Nov 2010-Oct 2011 Base Rate Rev | | | | | | | | | | |
| 28 | Act Nov 2011-Oct 2012 Base Rate Rev | | | | | | | | | | |
| 29 | AES collections | | | | | | | | | | - |
| 30 | Gas Street overcollection | | | | | | | | | | - |
| 31 | Prior Period Pool under/overcollection | | 67,892 | 86,746 | 89,034 | 89,034 | - | - | - | - | |
| 32 | | | | | | | | | | | |
| 33 | | | | | | | | | | | |
| 34 | C Surcharge Subtotal | (113,174) | 67,892 | 86,746 | 89,034 | 89,034 | - | - | - | - | (113,174) |
| 35 | | | | | | | | | | | |
| 36 | | | | | | | | | | | |
| 37 | D Net balance to be recovered (A-B+C) | 67,892 | 86,746 | 89,034 | 89,034 | 89,034 | - | - | - | - | 89,034 |
| 38 | | | | | | | | | | | |
| 39 | E Allocation of Litigated Recovery | | - | | - | (89,034) | - | - | - | - | (89,034) |
| 40 | | | | | | | | | | | |
| 41 | Surcharge calculation 2007/2008 | | | | | | | | | | |
| 42 | Unrecovered costs (D+E) | - | - | - | | - | - | - | - | - | - |
| 43 | remaining life | 24 | 36 | 48 | 60 | 72 | 84 | 84 | 84 | 84 | |
| 44 | one year | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | |
| 45 | F amortization 2007/2008 | - | - | - | - | - | - | - | - | - | |
| 46 | | | | | | | | | | | |
| 47 | Required annual increase in rates 2007/2 | | | | | | | | | | |
| 48 | smaller of D or F | - | - | - | | - | - | - | - | - | - |
| 49 | | | | | | | | | | | |
| 50 | forecasted therm sales | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 |
| 51 | | | | | | | | | | | |
| 52 | surcharge per therm | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 |

1. While the recoveries are displayed on the Summary, Cash Recoveries by site, are not exclusive to a particular site.

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**Filed under the following protective orders:**
**Order No. 22,853 dated February 18, 1998 in Docket No. DR 97-130**
**Order No. 23,316 dated October 11, 1999 in Docket No. DG 99-132**

**EnergyNorth Natural Gas, Inc.**
**Environmental Remediation - MGPs**
**Tariff page 91**

**Keene**

| | | (9/03 - 9/04) pool #1 | (9/04 - 9/05) pool #2 | (9/05 - 9/06) pool #3 | (9/06 - 9/07) pool #4 | (9/07 - 9/08) pool #5 | (9/08 - 9/09) pool #6 | (9/09 - 9/10) pool #7 | (9/10 - 9/11) pool #8 | (9/11 - 9/12) pool #9 | subtotal |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 1 Remediation costs (i.o. 500061) | - | | | | | | | | | - |
| 2 | Remediation costs (i.o. 500005) | 10,165 | 6,606 | 35,111 | 8,766 | 32 | 269 | - | - | 488 | 61,437 |
| 3 | A Subtotal - remediation costs | 10,165 | 6,606 | 35,111 | 8,766 | 32 | 269 | - | - | 488 | 61,437 |
| 4 | | | | | | | | | | | - |
| 5 | Cash recoveries (i.o. 500061) | - | | | | | | | | | - |
| 6 | Cash recoveries (i.o. 500004) | - | | | | | | | | | - |
| 7 | Recovery costs (i.o. 500004) | | | 18,831 | 823 | - | - | - | - | | 19,655 |
| 8 | Transfer Credit from Gas Restructuring | | | | - | - | - | | | | - |
| 9 | B Subtotal - net recoveries | - | | 18,831 | 823 | - | - | - | - | - | 19,655 |
| 10 | | | | | | | | | | | |
| 11 | A-B Total net expenses to recover | 10,165 | 6,606 | 53,942 | 9,589 | 32 | 269 | - | - | 488 | 81,091 |
| 12 | | | | | | | | | | | - |
| 13 | | | | | | | | | | | - |
| 14 | Surcharge revenue: | | | | | | | | | | - |
| 15 | Act June 1998 - October 1998 | - | | | | | | | | | - |
| 16 | Act November 1998 - October 1999 | - | | | | | | | | | - |
| 17 | Act November 1999 - October 2000 | - | | | | | | | | | - |
| 18 | Act November 2000 - October 2001 | - | | | | | | | | | - |
| 19 | Act November 2001 - October 2002 | - | | | | | | | | | - |
| 20 | Act November 2002 - October 2003 | - | | | | | | | | | - |
| 21 | Act November 2003 - October 2004 | - | | | | | | | | | - |
| 22 | Act November 2004- October 2005 | - | - | | | | - | - | - | - | - |
| 23 | Act November 2005- October 2006 | - | - | | | | - | - | - | - | - |
| 24 | Act November 2006- October 2007 | - | - | (14,091) | | | | | | | (14,091) |
| 25 | Act November 2007- October 2008 | | | | | | | | | | - |
| 26 | Act Nov 2009-Oct 2010 Base Rate Rev | | | | | | | | | | |
| 27 | Act Nov 2010-Oct 2011 Base Rate Rev | | | | | | | | | | |
| 28 | Act Nov 2011-Oct 2012 Base Rate Rev | | | | | | | | | | |
| 29 | AES collections | | | | | | | | | | - |
| 30 | Gas Street overcollection | | | | | | | | | | - |
| 31 | Prior Period Pool under/overcollection | | 10,165 | 16,771 | 56,622 | 66,211 | - | - | - | - | |
| 32 | | | | | | | | | | | |
| 33 | | | | | | | | | | | |
| 34 | C Surcharge Subtotal | - | 10,165 | 2,680 | 56,622 | 66,211 | - | - | - | - | (14,091) |
| 35 | | | | | | | | | | | |
| 36 | | | | | | | | | | | |
| 37 | D Net balance to be recovered (A-B+C) | 10,165 | 16,771 | 56,622 | 66,211 | 66,244 | 269 | - | - | 488 | 67,001 |
| 38 | | | | | | | | | | | - |
| 39 | E Allocation of Litigated Recovery | - | - | - | - | (66,244) | (269) | - | - | - | (66,513) |
| 40 | | | | | | | | | | | - |
| 41 | Surcharge calculation 2007/2008 | | | | | | | | | | - |
| 42 | Unrecovered costs (D+E) | - | - | - | | | - | - | - | 488 | 488 |
| 43 | remaining life | 24 | 36 | 48 | 60 | 72 | 84 | 84 | 84 | 84 | |
| 44 | one year | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | |
| 45 | F amortization 2007/2008 | - | - | - | - | - | - | - | - | 70 | |
| 46 | | | | | | | | | | | |
| 47 | Required annual increase in rates 2007/2 | | | | | | | | | | |
| 48 | smaller of D or F | - | - | - | | | - | - | - | 70 | 70 |
| 49 | | | | | | | | | | | |
| 50 | forecasted therm sales | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 |
| 51 | | | | | | | | | | | |
| 52 | surcharge per therm | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 |

1. While the recoveries are displayed on the Summary, Cash Recoveries by site, are not exclusive to a particular site.

00000188

**Filed under the following protective orders:**
**Order No. 22,853 dated February 18, 1998 in Docket No. DR 97-130**
**Order No. 23,316 dated October 11, 1999 in Docket No. DG 99-132**

**EnergyNorth Natural Gas, Inc.**
**Environmental Remediation - MGPs**
**Tariff page 91**

| | | Concord | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (9/03 - 9/04) pool #1 | (9/04 - 9/05) pool #2 | Corrected per 1/24/07 Audit (9/05 - 9/06) pool #3 | Corrected per 2/08 Audit (9/06 - 9/07) pool #4 | (9/07 - 9/08) pool #5 | (9/08 - 9/09) pool #6 | (9/09 - 9/10) pool #7 | (9/10 - 9/11) pool #8 | (9/11 - 9/12) pool #9 | subtotal |
| 1 | 1 Remediation costs (i.o. 500061) | - | | | | | | | | | - |
| 2 | Remediation costs (i.o. 500005) | 22,191 | 220,932 | 44,345 | 109,642 | 8,006 | 77,063 | 49,403 | 180,032 | 289,103 | 1,000,717 |
| 3 | A Subtotal - remediation costs | 22,191 | 220,932 | 44,345 | 109,642 | 8,006 | 77,063 | 49,403 | 180,032 | 289,103 | 1,000,717 |
| 4 | | | | | | | | | | | - |
| 5 | Cash recoveries (i.o. 500061) | - | | (22,239) | (47,977) | (12,601) | 16,623 | (3,213) | (11,394) | (31,575) | (112,376) |
| 6 | Cash recoveries (i.o. 500004) | - | | | | | | | | | - |
| 7 | Recovery costs (i.o. 500004) | | | | | 1,432 | (1,007) | | | | 425 |
| 8 | Transfer Credit from Gas Restructuring | | | - | | | | | | | - |
| 9 | B Subtotal - net recoveries | - | - | (22,239) | (47,977) | (11,169) | 15,616 | (3,213) | (11,394) | (31,575) | (111,950) |
| 10 | | | | | | | | | | | |
| 11 | A-B Total net expenses to recover | 22,191 | 220,932 | 22,106 | 61,665 | (3,163) | 92,679 | 46,190 | 168,638 | 257,528 | 888,766 |
| 12 | | | | | | | | | | | - |
| 13 | | | | | | | | | | | - |
| 14 | Surcharge revenue: | | | | | | | | | | - |
| 15 | Act June 1998 - October 1998 | - | | | | | | | | | - |
| 16 | Act November 1998 - October 1999 | - | | | | | | | | | - |
| 17 | Act November 1999 - October 2000 | - | | | | | | | | | - |
| 18 | Act November 2000 - October 2001 | - | | | | | | | | | - |
| 19 | Act November 2001 - October 2002 | - | | | | | | | | | - |
| 20 | Act November 2002 - October 2003 | - | | | | | | | | | - |
| 21 | Act November 2003 - October 2004 | - | | | | | | | | | - |
| 22 | Act November 2004- October 2005 | | | | | | | | | | - |
| 23 | Act November 2005- October 2006 | - | (27,499) | | | - | - | - | - | - | (27,499) |
| 24 | Act November 2006- October 2007 | - | (28,181) | - | | | | | | | (28,181) |
| 25 | Act November 2007- October 2008 | | | | | | | | | | - |
| 26 | Act Nov 2009-Oct 2010 Base Rate Rev | | | | | | | | ($1,886) | | (1,886) |
| 27 | Act Nov 2010-Oct 2011 Base Rate Rev | | | | | | | | ($13,776) | | (13,776) |
| 28 | Act Nov 2011-Oct 2012 Base Rate Rev | | | | | | | | ($12,088) | | (12,088) |
| 29 | AES collections | | | | | | | | | | - |
| 30 | Gas Street overcollection | | | | | | | | | | - |
| 31 | Prior Period Pool under/overcollection | | 22,191 | 187,442 | 209,549 | 271,214 | - | - | - | - | |
| 32 | | | | | | | | | | | |
| 33 | | | | | | | | | | | |
| 34 | C Surcharge Subtotal | - | (33,490) | 187,442 | 209,549 | 271,214 | - | - | (27,750) | - | (83,431) |
| 35 | | | | | | | | | | | |
| 36 | | | | | | | | | | | |
| 37 | D Net balance to be recovered (A-B+C) | 22,191 | 187,442 | 209,549 | 271,214 | 268,051 | 92,679 | 46,190 | 140,888 | 257,528 | 805,335 |
| 38 | | | | | | | | | | | - |
| 39 | E Allocation of Litigated Recovery | - | - | - | - | (268,051) | (92,679) | (46,190) | (9,392) | - | (416,311) |
| 40 | | | | | | | | | | | - |
| 41 | Surcharge calculation 2007/2008 | | | | | | | | | | - |
| 42 | Unrecovered costs (D+E) | - | - | - | | - | - | - | 131,496 | 257,528 | 389,024 |
| 43 | remaining life | 36 | 48 | 60 | | 72 | 84 | 84 | 72 | 84 | |
| 44 | one year | 12 | 12 | 12 | | 12 | 12 | 12 | 12 | 12 | |
| 45 | F amortization 2007/2008 | - | - | - | | - | - | - | 21,916 | 36,790 | |
| 46 | | | | | | | | | | | |
| 47 | Required annual increase in rates 2007/2 | | | | | | | | | | |
| 48 | smaller of D or F | - | - | - | | - | - | - | 21,916 | 36,790 | 58,706 |
| 49 | | | | | | | | | | | |
| 50 | forecasted therm sales | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 |
| 51 | | | | | | | | | | | |
| 52 | surcharge per therm | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0001 | $0.0002 | $0.0004 |

1. While the recoveries are displayed on the Summary, Cash Recoveries by site, are not exclusive to a particular site.

00000189

**Filed under the following protective orders:**
**Order No. 22,853 dated February 18, 1998 in Docket No. DR 97-130**
**Order No. 23,316 dated October 11, 1999 in Docket No. DG 99-132**

**EnergyNorth Natural Gas, Inc.**
**Environmental Remediation - MGPs**
**Tariff page 91**

| | | General | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (9/02 - 9/03) pool #1 | (9/03 - 9/04) pool #2 | (9/04 - 9/05) pool #3 | Corrected per 1/24/07 Audit (9/05 - 9/06) pool #4 | (9/06 - 9/07) pool #5 | (9/07 - 9/08) pool #6 | (9/08 - 9/09) pool #7 | (9/09 - 9/10) pool #8 | (9/10 - 9/11) pool #9 | (9/11 - 9/12) pool #10 | subtotal | | | 2012 MGP Remediation subtotal |
| 1 | 1 Remediation costs (i.o. 500061) | - | | | | | | | | | | - | | | 17,382,014 |
| 2 | Remediation costs (i.o. 500005) | 3,208 | 538,903 | 208,128 | 34,355 | 22,017 | (181,000) | (26,884) | 4,199 | 69,286 | 93,034 | 765,246 | | | 16,055,400 |
| 3 | A Subtotal - remediation costs | 3,208 | 538,903 | 208,128 | 34,355 | 22,017 | (181,000) | (26,884) | 4,199 | 69,286 | 93,034 | 765,246 | | | 33,437,414 |
| 4 | | | | | | | | | | | | | | | |
| 5 | Cash recoveries (i.o. 500061) | - | | | | - | - | - | | | | - | | | (4,671,904) |
| 6 | Cash recoveries (i.o. 500004) | - | | | | | | | | | | - | | | (445,985) |
| 7 | Recovery costs (i.o. 500004) | | | | 290,155 | 31,826 | 16,012 | 23,953 | - | - | (14,068) | 347,878 | | | 2,288,374 |
| 8 | Transfer Credit from Gas Restructuring | (3,331) | | | - | | | | | | | (3,331) | | | (3,331) |
| 9 | B Subtotal - net recoveries | (3,331) | - | - | 290,155 | 31,826 | 16,012 | 23,953 | - | - | (14,068) | 344,547 | | | (2,832,846) |
| 10 | | | | | | | | | | | | | | | |
| 11 | A-B Total net expenses to recover | (123) | 538,903 | 208,128 | 324,511 | 53,844 | (164,988) | (2,931) | 4,199 | 69,286 | 78,967 | 1,109,794 | | | 30,604,568 |
| 12 | | | | | | | | | | | | | | | 30,604,568 |
| 13 | | | | | | | | | | | | | | | - |
| 14 | Surcharge revenue: | | | | | | | | | | | | | | |
| 15 | Act June 1998 - October 1998 | - | - | | | | | | | | | - | | | (54,889) |
| 16 | Act November 1998 - October 1999 | - | - | | | | | | | | | - | | | (538,143) |
| 17 | Act November 1999 - October 2000 | - | - | | | | | | | | | - | | | (912,804) |
| 18 | Act November 2000 - October 2001 | - | - | | | | | | | | | - | | | (1,336,776) |
| 19 | Act November 2001 - October 2002 | - | - | | | | | | | | | - | | | (1,679,228) |
| 20 | Act November 2002 - October 2003 | - | - | | | | | | | | | - | | | (1,732,442) |
| 21 | Act November 2003 - October 2004 | (8,265) | - | | | | | | | | | (8,265) | | | (1,428,735) |
| 22 | Act November 2004- October 2005 | | (70,898) | | | | | | | | | (70,898) | | | (1,403,787) |
| 23 | Act November 2005- October 2006 | | (68,748) | (27,499) | | | - | - | - | - | - | (96,247) | | | (1,694,877) |
| 24 | Act November 2006- October 2007 | | (77,499) | (28,181) | (49,318) | | | | | | | (154,998) | | | (2,141,793) |
| 25 | Act November 2007- October 2008 | | | | | | | | | | | - | | | - |
| 26 | Act Nov 2009-Oct 2010 Base Rate Rev | | | | | | | | | | | - | | | (10,611) |
| 27 | Act Nov 2010-Oct 2011 Base Rate Rev | | | | | | | | | | | - | | | (77,509) |
| 28 | Act Nov 2011-Oct 2012 Base Rate Rev | | | | | | | | | | | - | | | (68,011) |
| 29 | AES collections | | - | | | | | | | | | - | | | (134,711) |
| 30 | Gas Street overcollection | | | | | | | | | | | - | | | (23,511) |
| 31 | Prior Period Pool under/overcollection | | (8,388) | 313,370 | 465,817 | 741,010 | 794,853 | - | - | - | - | | | | |
| 32 | | | | | | | | | | | | | | | |
| 33 | | | | | | | | | | | | | | | |
| 34 | C Surcharge Subtotal | (8,265) | (225,533) | 257,689 | 416,499 | 741,010 | 794,853 | - | - | - | - | (330,408) | | (13,237,827) | (13,237,827) |
| 35 | | | | | | | | | | | | | | | |
| 36 | | | | | | | | | | | | | | | |
| 37 | D Net balance to be recovered (A-B+C) | (8,388) | 313,370 | 465,817 | 741,010 | 794,853 | 629,865 | (2,931) | 4,199 | 69,286 | 78,967 | 779,385 | 2,162,346 | 17,366,741 | 17,366,741 |
| 38 | | | | | | | | | | | | | - | | |
| 39 | E Allocation of Litigated Recovery | - | - | - | - | - | (629,865) | 2,931 | (4,199) | (15,337) | - | (646,470) | (428,437) | (15,614,032) | (15,614,032) |
| 40 | | | | | | | | | | | | | - | | 1,752,709 |
| 41 | Surcharge calculation 2007/2008 | | | | | | | | | | | | - | | 837,716 |
| 42 | Unrecovered costs (D+E) | - | - | - | - | | - | - | - | 53,949 | 78,967 | 132,915 | 1,734,186 | 1,734,186 | |
| 43 | remaining life | | 36 | 48 | 60 | 72 | 84 | 84 | 84 | 72 | 84 | | | | |
| 44 | one year | | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | | | | |
| 45 | F amortization 2007/2008 | | - | - | - | - | - | - | - | 8,991 | 11,281 | | | | |
| 46 | | | | | | | | | | | | | | | |
| 47 | Required annual increase in rates 2007/2 | | | | | | | | | | | | | | |
| 48 | smaller of D or F | - | - | - | - | | - | - | - | 8,991 | 11,281 | 20,272 | 256,547 | 256,547 | |
| 49 | | | | | | | | | | | | | | | |
| 50 | forecasted therm sales | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | 158,062,349 | | | **158,062,349** |
| 51 | | | | | | | | | | | | | | | |
| 52 | surcharge per therm | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0001 | $0.0001 | $0.0001 | | | **$0.0016** |

1. While the recoveries are displayed on the Summary, Cash Recoveries by site, are not exclusive to a particular site.

00000190

**Filed under the following protective orders:**
**Order No. 22,853 dated February 18, 1998 in Docket No. DR 97-130**
**Order No. 23,316 dated October 11, 1999 in Docket No. DG 99-132**

**EnergyNorth Natural Gas, Inc.**
**Environmental Remediation - MGPs**
**Tariff page 91**

**Cash Recoveries**[1]

| | | (9/11 - 9/12) Concord Pond | (9/10 - 9/11) Concord Pond | (9/09 - 9/10) Concord Pond | (9/08 - 9/09) Concord Pond | (9/07 - 9/08) Concord Pond | (9/06 - 9/07) Concord Pond | (9/05 - 9/06) Concord Pond | (9/04- 9/05) Concord Pond | (9/03 - 9/04) Concord Pond | (9/11 - 9/12) Laconia | (9/10 - 9/11) Laconia | (9/09 - 9/10) Laconia | (9/08 - 9/09) Laconia | (9/07 - 9/08) Laconia | (9/06 - 9/07) Laconia |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 1 Remediation costs (i.o. 500061) | - | - | - | - | - | | - | - | - | - | - | - | - | - | |
| 2 | Remediation costs (i.o. 500005) | - | - | - | - | - | | - | - | - | - | - | - | - | - | |
| 3 | A Subtotal - remediation costs | - | - | - | - | - | | - | - | - | - | - | - | - | - | |
| 4 | | | | | | | | | | | | | | | | |
| 5 | Cash recoveries (i.o. 500061) | | | | | | | | | | | | | | | |
| 6 | Cash recoveries (i.o. 500004) | | | | - | 568 | - | - | - | (648,000) | - | - | - | - | - | - |
| 7 | Recovery costs (i.o. 500004) | | | | - | - | - | 73 | - | 658,508 | | | | - | - | 45 |
| 8 | Transfer Credit from Gas Restructuring | | | | - | - | - | - | - | - | | | | | | |
| 9 | B Subtotal - net recoveries | - | - | - | - | 568 | - | 73 | - | 10,508 | - | - | - | - | - | 45 |
| 10 | | | | | | | | | | | | | | | | |
| 11 | A-B Total net expenses to recover | - | - | - | - | 568 | - | 73 | - | 10,508 | - | - | - | - | - | 45 |
| 12 | | | | | | | | | | | | | | | | |
| 13 | | | | | | | | | | | | | | | | |
| 14 | Surcharge revenue: | | | | | | | | | | | | | | | |
| 15 | Act June 1998 - October 1998 | - | - | - | - | - | | - | - | - | | | | | | |
| 16 | Act November 1998 - October 1999 | - | - | - | - | - | | - | - | - | | | | | | |
| 17 | Act November 1999 - October 2000 | - | - | - | - | - | | - | - | - | | | | | | |
| 18 | Act November 2000 - October 2001 | - | - | - | - | - | | - | - | - | | | | | | |
| 19 | Act November 2001 - October 2002 | - | - | - | - | - | | - | - | - | | | | | | |
| 20 | Act November 2002 - October 2003 | - | - | - | - | - | | - | - | - | | | | | | |
| 21 | Act November 2003 - October 2004 | - | - | - | - | - | | - | - | - | | | | | | |
| 22 | Act November 2004- October 2005 | | | | | | | | | | | | | | | |
| 23 | Act November 2005- October 2006 | | | | | | | | | | | | | | | |
| 24 | Act November 2006- October 2007 | | | | | | | | | | | | | | | |
| 25 | Act November 2007- October 2008 | | | | | | | | | | | | | | | |
| 26 | Act Nov 2009-Oct 2010 Base Rate Rev | | | | | | | | | | | | | | | |
| 27 | Act Nov 2010-Oct 2011 Base Rate Rev | | | | | | | | | | | | | | | |
| 28 | Act Nov 2011-Oct 2012 Base Rate Rev | | | | | | | | | | | | | | | |
| 29 | AES collections | - | - | - | - | - | | - | - | - | | | | | | |
| 30 | Gas Street overcollection | - | - | - | - | - | | - | - | - | | | | | | |
| 31 | Prior Period Pool under/overcollection | | | | | | | | | | | | | | | |
| 32 | | | | | | | | | | | | | | | | |
| 33 | | | | | | | | | | | | | | | | |
| 34 | C Surcharge Subtotal | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 35 | | | | | | | | | | | | | | | | |
| 36 | | | | | | | | | | | | | | | | |
| 37 | D Net balance to be recovered (A-B+C) | - | - | - | - | 568 | - | 73 | - | 10,508 | - | - | - | - | - | 45 |
| 38 | | | | | | | | | | | | | | | | |
| 39 | E Allocation of Litigated Recovery | | | | | | | | | | | | | | | |
| 40 | | | | | | | | | | | | | | | | |
| 41 | Surcharge calculation 2007/2008 | | | | | | | | | | | | | | | |
| 42 | Unrecovered costs (D+E) | | | | | | | | | | | | | | | |
| 43 | remaining life | | | | | | | | | | | | | | | |
| 44 | one year | | | | | | | | | | | | | | | |
| 45 | F amortization 2007/2008 | | | | | | | | | | | | | | | |
| 46 | | | | | | | | | | | | | | | | |
| 47 | Required annual increase in rates 2007/2 | | | | | | | | | | | | | | | |
| 48 | smaller of D or F | | | | | | | | | | | | | | | |
| 49 | | | | | | | | | | | | | | | | |
| 50 | forecasted therm sales | | | | | | | | | | | | | | | |
| 51 | | | | | | | | | | | | | | | | |
| 52 | surcharge per therm | | | | | | | | | | | | | | | |

1. While the recoveries are displayed on the Summary, Cash Recoveries by site, are not exclusive to a particular site.

00000191

**Filed under the following protective orders:**
**Order No. 22,853 dated February 18, 1998 in Docket No. DR 97-130**
**Order No. 23,316 dated October 11, 1999 in Docket No. DG 99-132**

**EnergyNorth Natural Gas, Inc.**
**Environmental Remediation - MGPs**
**Tariff page 91**

| | | Corrected per 1/24/07 Audit (9/05 - 9/06) Laconia | (9/04 - 9/05) Laconia | (9/03 - 9/04) Laconia | (9/11 - 9/12) Manchester | (9/10 - 9/11) Manchester | (9/09 - 9/10) Manchester | (9/08 - 9/09) Manchester | (9/07 - 9/08) Manchester | (9/06 - 9/07) Manchester | Corrected per 1/24/07 Audit (9/05 - 9/06) Manchester | (9/04 - 9/05) Manchester | (9/03 - 9/04) Manchester | (9/11 - 9/12) Nashua | (9/10 - 9/11) Nashua | (9/09 - 9/10) Nashua | (9/08 - 9/09) Nashua | (9/07 - 9/08) Nashua |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 1 Remediation costs (i.o. 500061) | | - | - | - | - | | | | | | | | - | - | - | - | - |
| 2 | Remediation costs (i.o. 500005) | | - | - | | | | | | | | | | - | - | - | - | - |
| 3 | A Subtotal - remediation costs | | - | - | | | | | | | | | | - | - | - | - | - |
| 4 | | | | | | | | | | | | | | | | | | |
| 5 | Cash recoveries (i.o. 500061) | | | | | | | | | | | | | | | | | |
| 6 | Cash recoveries (i.o. 500004) | - | (23,619) | (2,677,000) | | | | 9,679 | - | (630,000) | (1,725,792) | (754,938) | - | - | - | - | | (1,032,186) |
| 7 | Recovery costs (i.o. 500004) | 22,240 | 486,894 | 1,492,967 | - | - | - | (2,008,365) | 77,222 | 195,929 | 941,433 | 307,062 | 951,425 | | | | | 561,030 |
| 8 | Transfer Credit from Gas Restructuring | | | | | | | | | | | | | | | | | |
| 9 | B Subtotal - net recoveries | 22,240 | 463,275 | (1,184,033) | - | - | - | (1,998,686) | 77,222 | (434,071) | (784,359) | (447,876) | 951,425 | - | - | - | - | (471,155) |
| 10 | | | | | | | | | | | | | | | | | | |
| 11 | A-B Total net expenses to recover | 22,240 | 463,275 | (1,184,033) | - | - | - | (1,998,686) | 77,222 | (434,071) | (784,359) | (447,876) | 951,425 | - | - | - | - | (471,155) |
| 12 | | | | | | | | | | | | | | | | | | |
| 13 | | | | | | | | | | | | | | | | | | |
| 14 | Surcharge revenue: | | | | | | | | | | | | | | | | | |
| 15 | Act June 1998 - October 1998 | | | | - | - | - | - | - | | - | - | | | | | | |
| 16 | Act November 1998 - October 1999 | | | | - | - | - | - | - | - | - | - | | | | | | |
| 17 | Act November 1999 - October 2000 | | | | - | - | - | - | - | - | - | - | | | | | | |
| 18 | Act November 2000 - October 2001 | | | | - | - | - | - | - | - | - | - | | | | | | |
| 19 | Act November 2001 - October 2002 | | | | - | - | - | - | - | - | - | - | | | | | | |
| 20 | Act November 2002 - October 2003 | | | | - | - | - | - | - | - | - | - | | | | | | |
| 21 | Act November 2003 - October 2004 | | | | - | - | - | - | - | - | - | - | | | | | | |
| 22 | Act November 2004- October 2005 | | | | | | | | | | | | | | | | | |
| 23 | Act November 2005- October 2006 | | | | | | | | | | - | - | | | | | | |
| 24 | Act November 2006- October 2007 | | | | | | | | | | | | | | | | | |
| 25 | Act November 2007- October 2008 | | | | | | | | | | | | | | | | | |
| 26 | Act Nov 2009-Oct 2010 Base Rate Rev | | | | | | | | | | | | | | | | | |
| 27 | Act Nov 2010-Oct 2011 Base Rate Rev | | | | | | | | | | | | | | | | | |
| 28 | Act Nov 2011-Oct 2012 Base Rate Rev | | | | | | | | | | | | | | | | | |
| 29 | AES collections | | | | - | - | - | - | - | - | | | | | | | | |
| 30 | Gas Street overcollection | | | | - | - | - | - | - | - | | | | | | | | |
| 31 | Prior Period Pool under/overcollection | | | | | | | | | | - | - | | | | | | |
| 32 | | | | | | | | | | | | | | | | | | |
| 33 | | | | | | | | | | | - | - | | | | | | |
| 34 | C Surcharge Subtotal | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 35 | | | | | | | | | | | | | | | | | | |
| 36 | | | | | | | | | | | | | | | | | | |
| 37 | D Net balance to be recovered (A-B+C) | 22,240 | 463,275 | (1,184,033) | - | - | - | (1,998,686) | 77,222 | (434,071) | (784,359) | (447,876) | 951,425 | - | - | - | - | (471,155) |
| 38 | | | | | | | | | | | | | | | | | | |
| 39 | E Allocation of Litigated Recovery | | | | | | | | | | | | | | | | | |
| 40 | | | | | | | | | | | | | | | | | | |
| 41 | Surcharge calculation 2007/2008 | | | | | | | | | | | | | | | | | |
| 42 | Unrecovered costs (D+E) | | | | | | | | | | | | | | | | | |
| 43 | remaining life | | | | | | | | | | | | | | | | | |
| 44 | one year | | | | | | | | | | | | | | | | | |
| 45 | F amortization 2007/2008 | | | | | | | | | | | | | | | | | |
| 46 | | | | | | | | | | | | | | | | | | |
| 47 | Required annual increase in rates 2007/2 | | | | | | | | | | | | | | | | | |
| 48 | smaller of D or F | | | | | | | | | | | | | | | | | |
| 49 | | | | | | | | | | | | | | | | | | |
| 50 | forecasted therm sales | | | | | | | | | | | | | | | | | |
| 51 | | | | | | | | | | | | | | | | | | |
| 52 | surcharge per therm | | | | | | | | | | | | | | | | | |

1. While the recoveries are displayed on the Summary, Cash Recoveries by site, are not exclusive to a particular site.

00000192

**ıe following protective orders:**
**. 22,853 dated February 18, 1998 in Docket No. DR 97-130**
**. 23,316 dated October 11, 1999 in Docket No. DG 99-132**

**Natural Gas, Inc.**
**ıl Remediation - MGPs**

| | | (9/06 - 9/07) Nashua | (9/05 - 9/06) Nashua | (9/04 - 9/05) Nashua | (9/03 - 9/04) Nashua | (9/11 - 9/12) Dover | (9/10 - 9/11) Dover | (9/09 - 9/10) Dover | (9/08 - 9/09) Dover | (9/07 - 9/08) Dover | (9/06 - 9/07) Dover | (9/05 - 9/06) Dover | (9/04 - 9/05) Dover | (9/03 - 9/04) Dover | (9/10 - 9/11) Keene | (9/10 - 9/11) Keene |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 1 Remediation costs (i.o. 500061) | | | - | | - | - | - | - | - | | - | - | | - | - |
| 2 | Remediation costs (i.o. 500005) | | | - | | - | - | - | - | - | | - | - | | | |
| 3 | A Subtotal - remediation costs | | | - | | - | - | - | - | - | | - | - | | | |
| 4 | | | | | | | | | | | | | | | | |
| 5 | Cash recoveries (i.o. 500061) | | | | | | | | | | | | | | | |
| 6 | Cash recoveries (i.o. 500004) | (544,402) | (625,000) | (782,450) | (795,000) | - | - | - | - | (2,133) | - | (237,489) | (7,150) | (645,500) | - | - |
| 7 | Recovery costs (i.o. 500004) | 78,298 | 645,302 | 537,552 | 655,683 | | | | (92,947) | - | 14,848 | 117,621 | 517,891 | 500,868 | | |
| 8 | Transfer Credit from Gas Restructuring | | | | | | | | | | | | | | | |
| 9 | B Subtotal - net recoveries | (466,104) | 20,302 | (244,898) | (139,317) | - | - | - | (92,947) | (2,133) | 14,848 | (119,868) | 510,741 | (144,632) | - | - |
| 10 | | | | | | | | | | | | | | | | |
| 11 | A-B Total net expenses to recover | (466,104) | 20,302 | (244,898) | (139,317) | - | - | - | (92,947) | (2,133) | 14,848 | (119,868) | 510,741 | (144,632) | - | - |
| 12 | | | | | | | | | | | | | | | | |
| 13 | | | | | | | | | | | | | | | | |
| 14 | Surcharge revenue: | | | | | | | | | | | | | | | |
| 15 | Act June 1998 - October 1998 | | | | | | | | | | | | | | | |
| 16 | Act November 1998 - October 1999 | | | | | | | | | | | | | | | |
| 17 | Act November 1999 - October 2000 | | | | | | | | | | | | | | | |
| 18 | Act November 2000 - October 2001 | | | | | | | | | | | | | | | |
| 19 | Act November 2001 - October 2002 | | | | | | | | | | | | | | | |
| 20 | Act November 2002 - October 2003 | | | | | | | | | | | | | | | |
| 21 | Act November 2003 - October 2004 | | | | | | | | | | | | | | | |
| 22 | Act November 2004- October 2005 | | | | | | | | | | | | | | | |
| 23 | Act November 2005- October 2006 | | | | | | | | | | | | | | | |
| 24 | Act November 2006- October 2007 | | | | | | | | | | | | | | | |
| 25 | Act November 2007- October 2008 | | | | | | | | | | | | | | | |
| 26 | Act Nov 2009-Oct 2010 Base Rate Rev | | | | | | | | | | | | | | | |
| 27 | Act Nov 2010-Oct 2011 Base Rate Rev | | | | | | | | | | | | | | | |
| 28 | Act Nov 2011-Oct 2012 Base Rate Rev | | | | | | | | | | | | | | | |
| 29 | AES collections | | | | | | | | | | | | | | | |
| 30 | Gas Street overcollection | | | | | | | | | | | | | | | |
| 31 | Prior Period Pool under/overcollection | | | | | | | | | | | | | | | |
| 32 | | | | | | | | | | | | | | | | |
| 33 | | | | | | | | | | | | | | | | |
| 34 | C Surcharge Subtotal | - | - | - | - | - | - | - | - | - | - | - | - | - | | |
| 35 | | | | | | | | | | | | | | | | |
| 36 | | | | | | | | | | | | | | | | |
| 37 | D Net balance to be recovered (A-B+C) | (466,104) | 20,302 | (244,898) | (139,317) | - | - | - | (92,947) | (2,133) | 14,848 | (119,868) | 510,741 | (144,632) | - | - |
| 38 | | | | | | | | | | | | | | | | |
| 39 | E Allocation of Litigated Recovery | | | | | | | | | | | | | | | |
| 40 | | | | | | | | | | | | | | | | |
| 41 | Surcharge calculation 2007/2008 | | | | | | | | | | | | | | | |
| 42 | Unrecovered costs (D+E) | | | | | | | | | | | | | | | |
| 43 | remaining life | | | | | | | | | | | | | | | |
| 44 | one year | | | | | | | | | | | | | | | |
| 45 | F amortization 2007/2008 | | | | | | | | | | | | | | | |
| 46 | | | | | | | | | | | | | | | | |
| 47 | Required annual increase in rates 2007/2 | | | | | | | | | | | | | | | |
| 48 | smaller of D or F | | | | | | | | | | | | | | | |
| 49 | | | | | | | | | | | | | | | | |
| 50 | forecasted therm sales | | | | | | | | | | | | | | | |
| 51 | | | | | | | | | | | | | | | | |
| 52 | surcharge per therm | | | | | | | | | | | | | | | |

1. While the recoveries are displayed on the Summary, Cash Recoveries by site, are not exclusive to a particular site.

00000193

**Filed under the following protective orders:**
**Order No. 22,853 dated February 18, 1998 in Docket No. DR 97-130**
**Order No. 23,316 dated October 11, 1999 in Docket No. DG 99-132**

**EnergyNorth Natural Gas, Inc.**
**Environmental Remediation - MGPs**
**Tariff page 91**

| | | (9/09 - 9/10) Keene | (9/08 - 9/09) Keene | (9/07 - 9/08) Keene | (9/06 - 9/07) Keene | (9/05 - 9/06) Keene | (9/04 - 9/05) Keene | (9/03 - 9/04) Keene | (9/06 - 9/07) General | 2012 subtotal | MGP TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 1 Remediation costs (i.o. 500061) | | | | | - | - | | | - | 17,382,014 |
| 2 | Remediation costs (i.o. 500005) | | | | | - | - | | | - | 16,055,400 |
| 3 | A Subtotal - remediation costs | | | | | - | - | | | - | 33,437,414 |
| 4 | | | | | | | | | | | (27,910,297) |
| 5 | Cash recoveries (i.o. 500061) | | | | | | | | | - | (4,671,904) |
| 6 | Cash recoveries (i.o. 500004) | - | 116 | | | (700,000) | (211,213) | 0 | (10,760,900) | (22,792,408) | (23,238,393) |
| 7 | Recovery costs (i.o. 500004) | | | 1,559 | 28,211 | 309,618 | 56,392 | 121,018 | | 7,178,376 | 9,466,750 |
| 8 | Transfer Credit from Gas Restructuring | | | | | | | | | - | (3,331) |
| 9 | B Subtotal - net recoveries | - | 116 | 1,559 | 28,211 | (390,382) | (154,821) | 121,018 | (10,760,900) | (15,614,032) | (18,446,878) |
| 10 | | | | | | | | | | - | - |
| 11 | A-B Total net expenses to recover | - | 116 | 1,559 | 28,211 | (390,382) | (154,821) | 121,018 | (10,760,900) | (15,614,032) | 14,990,536 |
| 12 | | | | | | | | | | | |
| 13 | | | | | | | | | | | |
| 14 | Surcharge revenue: | | | | | | | | | | |
| 15 | Act June 1998 - October 1998 | | | | | | | | | - | (54,889) |
| 16 | Act November 1998 - October 1999 | | | | | | | | | - | (538,143) |
| 17 | Act November 1999 - October 2000 | | | | | | | | | - | (912,804) |
| 18 | Act November 2000 - October 2001 | | | | | | | | | - | (1,336,776) |
| 19 | Act November 2001 - October 2002 | | | | | | | | | - | (1,679,228) |
| 20 | Act November 2002 - October 2003 | | | | | | | | | - | (1,732,442) |
| 21 | Act November 2003 - October 2004 | | | | | | | | | - | (1,428,735) |
| 22 | Act November 2004- October 2005 | | | | | | | | | - | (1,403,787) |
| 23 | Act November 2005- October 2006 | | | | | | | | | | (1,694,877) |
| 24 | Act November 2006- October 2007 | | | | | | | | | | (2,141,793) |
| 25 | Act November 2007- October 2008 | | | | | | | | | | - |
| 26 | Act Nov 2009-Oct 2010 Base Rate Rev | | | | | | | | | | (10,611) |
| 27 | Act Nov 2010-Oct 2011 Base Rate Rev | | | | | | | | | | (77,509) |
| 28 | Act Nov 2011-Oct 2012 Base Rate Rev | | | | | | | | | | (68,011) |
| 29 | AES collections | | | | | | | | | - | (134,711) |
| 30 | Gas Street overcollection | | | | | | | | | - | (23,511) |
| 31 | Prior Period Pool under/overcollection | | | | | | | | | - | |
| 32 | | | | | | | | | | | |
| 33 | | | | | | | | | | - | |
| 34 | C Surcharge Subtotal | | | | - | - | - | - | | - | (13,237,827) |
| 35 | | | | | | | | | | - | (156,131) |
| 36 | | | | | | | | | | - | |
| 37 | D Net balance to be recovered (A-B+C) | - | 116 | 1,559 | 28,211 | (390,382) | (154,821) | 121,018 | (10,760,900) | (15,614,032) | 1,752,709 |
| 38 | | | | | | | | | | | |
| 39 | E Allocation of Litigated Recovery | | | | | | | | | 15,614,032 | |
| 40 | | | | | | | | | | - | |
| 41 | Surcharge calculation 2007/2008 | | | | | | | | | | |
| 42 | Unrecovered costs (D+E) | | | | | | | | | | |
| 43 | remaining life | | | | | | | | | | |
| 44 | one year | | | | | | | | | | |
| 45 | F amortization 2007/2008 | | | | | | | | | | |
| 46 | | | | | | | | | | | |
| 47 | Required annual increase in rates 2007/2 | | | | | | | | | | |
| 48 | smaller of D or F | | | | | | | | | | |
| 49 | | | | | | | | | | | |
| 50 | forecasted therm sales | | | | | | | | | | |
| 51 | | | | | | | | | | | |
| 52 | surcharge per therm | | | | | | | | | | |

1. While the recoveries are displayed on the Summary, Cash Recoveries by site, are not exclusive to a particular site.

00000194

**Filed under the following protective orders:**
**Order No. 22,853 dated February 18, 1998 in Docket No. DR 97-130**
**Order No. 23,316 dated October 11, 1999 in Docket No. DG 99-132**

**EnergyNorth Natural Gas, Inc.**
**Environmental Remediation - MGPs**
**Tariff page 91**

**Expense and Collection Summary per Year**

| | | (thru 3/98) | (4/98 - 9/98) | 10/98 - 9/15/99 | (9/99 - 9/00) | (9/00 - 9/01) | (9/01 - 9/02) | (9/02 - 9/03) | (9/03 - 9/04) | (9/04 - 9/05) | (9/05 - 9/06) | (9/06 - 9/07) | (9/07 - 9/08) | (9/08 - 9/09) | (9/09 - 9/10) | (9/10 - 9/11) | (9/11 - 9/12) | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 1 Remediation costs (i.o. 500061) | 1,422,811 | 1,843,806 | 2,154,235 | 129,002 | - | - | - | 406,472 | 2,236,682 | 997,637 | 726,742 | 4,590,624 | 518,907 | 674,766 | 686,896 | 993,434 | 17,382,014 |
| 2 | Remediation costs (i.o. 500005) | - | - | 1,027,747 | 3,513,285 | 2,428,832 | 362,663 | 689,437 | 571,259 | 445,367 | 2,444,366 | 2,229,625 | 255,263 | 658,324 | 316,280 | 461,046 | 651,906 | 16,055,400 |
| 3 | A Subtotal - remediation costs | 1,422,811 | 1,843,806 | 3,181,982 | 3,642,287 | 2,428,832 | 362,663 | 689,437 | 977,731 | 2,682,050 | 3,442,003 | 2,956,367 | 4,845,887 | 1,177,231 | 991,045 | 1,147,942 | 1,645,340 | 33,437,414 |
| 4 | | | | | | | | | | | | | | | | | | |
| 5 | Cash recoveries (i.o. 500061) | (1,080,580) | (434,476) | (499,684) | (33,204) | - | - | - | - | - | (600,673) | (285,927) | (1,150,452) | (58,231) | (113,390) | (310,226) | (105,062) | (4,671,904) |
| 6 | Cash recoveries (i.o. 500004) | (445,985) | - | - | - | - | - | - | (4,765,500) | (1,779,370) | (3,288,281) | (11,935,301) | (1,033,751) | 9,795 | - | - | - | (23,238,393) |
| 7 | Recovery costs (i.o. 500004) | 623,784 | - | - | - | - | - | - | 5,622,795 | 1,905,791 | 2,350,722 | 377,106 | 678,985 | (2,078,366) | - | - | (14,068) | 9,466,750 |
| 8 | Transfer Credit from Gas Restructuring | - | - | - | - | - | - | (3,331) | - | - | - | - | - | - | - | - | - | (3,331) |
| 9 | B Subtotal - net recoveries | (902,781) | (434,476) | (499,684) | (33,204) | - | - | (3,331) | 857,295 | 126,421 | (1,538,231) | (11,844,123) | (1,505,218) | (2,126,802) | (113,390) | (310,226) | (119,129) | (18,446,878) |
| 10 | | | | | | | | | | | | | | | | | | |
| 11 | A-B Total net expenses to recover | 520,030 | 1,409,330 | 2,682,299 | 3,609,083 | 2,428,832 | 362,663 | 686,106 | 1,835,026 | 2,808,471 | 1,903,772 | (8,887,756) | 3,340,669 | (949,571) | 877,655 | 837,716 | 1,526,211 | 14,990,536 |
| 12 | | | | | | | | | | | | | | | | | | |
| 13 | | | | | | | | | | | | | | | | | | |
| 14 | Surcharge revenue: | | | | | | | | | | | | | | | | | |
| 15 | Act June 1998 - October 1998 | (54,889) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (54,889) |
| 16 | Act November 1998 - October 1999 | (287,010) | (251,133) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (538,143) |
| 17 | Act November 1999 - October 2000 | (178,131) | (266,400) | (468,273) | - | - | - | - | - | - | - | - | - | - | - | - | - | (912,804) |
| 18 | Act November 2000 - October 2001 | - | (292,420) | (487,366) | (556,990) | - | - | - | - | - | - | - | - | - | - | - | - | (1,336,776) |
| 19 | Act November 2001 - October 2002 | - | (281,914) | (478,029) | (551,571) | (367,714) | - | - | - | - | - | - | - | - | - | - | - | (1,679,228) |
| 20 | Act November 2002 - October 2003 | - | (258,347) | (486,300) | (562,284) | (364,725) | (60,787) | - | - | - | - | - | - | - | - | - | - | (1,732,442) |
| 21 | Act November 2003 - October 2004 | - | (14,567) | (407,875) | (480,710) | (349,608) | (43,701) | (132,274) | - | - | - | - | - | - | - | - | - | (1,428,735) |
| 22 | Act November 2004- October 2005 | - | - | (184,336) | (453,749) | (326,132) | (42,539) | (99,258) | (297,773) | - | - | - | - | - | - | - | - | (1,403,787) |
| 23 | Act November 2005- October 2006 | - | - | (141,176) | (460,610) | (316,240) | (54,998) | (96,247) | (281,866) | (343,739) | - | - | - | - | - | - | - | (1,694,877) |
| 24 | Act November 2006- October 2007 | - | - | - | (549,539) | (338,178) | (56,363) | (112,726) | (288,860) | (366,359) | (429,768) | - | - | - | - | - | - | (2,141,793) |
| 25 | Act November 2007- October 2008 | | | | | | | | | | | | | | | | - | - |
| 26 | Act Nov 2009-Oct 2010 Base Rate Rev | | | | | | | | | | | | | | | (10,611) | | (10,611) |
| 27 | Act Nov 2010-Oct 2011 Base Rate Rev | | | | | | | | | | | | | | | (77,509) | | (77,509) |
| 28 | Act Nov 2011-Oct 2012 Base Rate Rev | | | | | | | | | | | | | | | (68,011) | | (68,011) |
| 29 | AES collections | - | - | - | - | - | - | - | (33,593) | (11,626) | (11,901) | (12,271) | (12,620) | (12,904) | (13,145) | (13,221) | (13,429) | (134,711) |
| 30 | Gas Street overcollection | - | (23,511) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (23,511) |
| 31 | Prior Period Pool under/overcollection | | | | | | | | | | | | | | | | | |
| 32 | | | | | | | | | | | | | | | | | | |
| 33 | | | | | | | | | | | | | | | | | | |
| 34 | C Surcharge Subtotal | (520,030) | (1,388,292) | (2,653,355) | (3,615,454) | (2,062,596) | (258,389) | (440,504) | (902,092) | (721,725) | (441,669) | (12,271) | (12,620) | (12,904) | (13,145) | (169,352) | (13,429) | (13,237,827) |
| 35 | | | | | | | | | | | | | | | | | | |
| 36 | | | | | | | | | | | | | | | | | | |
| 37 | D Net balance to be recovered (A-B+C) | - | 21,038 | 28,944 | (6,371) | 366,236 | 104,274 | 245,602 | 932,934 | 2,086,746 | 1,462,103 | (8,900,027) | 3,328,049 | (962,475) | 864,510 | 668,364 | 1,512,782 | 1,752,709 |
| 38 | | | | | | | | | | | | | | | | | | |
| 39 | E Allocation of Litigated Recovery | | | | | | | | | | | | | | | | | |
| 40 | | | | | | | | | | | | | | | | | | |
| 41 | Surcharge calculation 2007/2008 | | | | | | | | | | | | | | | | | |
| 42 | Unrecovered costs (D+E) | | | | | | | | | | | | | | | | | |
| 43 | remaining life | | | | | | | | | | | | | | | | | |
| 44 | one year | | | | | | | | | | | | | | | | | |
| 45 | F amortization 2007/2008 | | | | | | | | | | | | | | | | | |
| 46 | | | | | | | | | | | | | | | | | | |
| 47 | Required annual increase in rates 2007/2 | | | | | | | | | | | | | | | | | |
| 48 | smaller of D or F | | | | | | | | | | | | | | | | | |
| 49 | | | | | | | | | | | | | | | | | | |
| 50 | forecasted therm sales | | | | | | | | | | | | | | | | | |
| 51 | | | | | | | | | | | | | | | | | | |
| 52 | surcharge per therm | | | | | | | | | | | | | | | | | |

1. While the recoveries are displayed on the Summary, Cash Recoveries by site, are not exclusive to a particular site.

00000195

**ENERGYNORTH NATURAL GAS, INC.**
**d/b/a LIBERTY UTILITIES**

**CONCORD FORMER MGP**

LINE
NO.

1. SITE LOCATION: One Gas Street, Concord, New Hampshire.

2. DATE SITE WAS FIRST INVESTIGATED: EnergyNorth Natural Gas, Inc. (ENGI) received a Notice Letter from the New Hampshire Department of Environmental Services (NHDES) in September 1992. The Notice related primarily to contamination identified in the pond adjacent to Exit 13 off Interstate 93, although it was broad enough to also include the former manufactured gas plant (MGP) site itself.

3. NATURE AND SCOPE OF SITE CONTAMINATION: Residual materials from the historic operation of the MGP were discovered in the area of the Exit 13 pond, as the NHDOT began site preparation work for the reconfiguration of that interchange. Subsequent investigations by ENGI and others indicate that contaminants originating from the MGP on Gas Street are present in soil and groundwater between the MGP and the Merrimack River, including within the Exit 13 pond.

4. SUMMARY OF MATERIAL DEVELOPMENTS AND INTERACTIONS WITH ENVIRONMENTAL AUTHORITIES: ENGI has continued to monitor groundwater semiannually at the Exit 13 pond, in May and November, as required by the Groundwater Management Zone Permit that was issued in 1999 as part of the overall remedy following the remediation of the southern end of the Exit 13 pond. The permit was renewed in 2003 and 2007, and NHDES specified semiannual collection of surface water samples from the pond as an additional condition of the permit. These sample results will be evaluated over time to address the efficacy of the existing Exit 13 pond remedy, and determine if additional treatment may be necessary. A groundwater sampling round for the MGP site was conducted in August 2010 and included monitoring wells located on the MGP site itself as well as a number of wells located offsite. In addition, a Supplemental Data Collection Work Plan for the collection of off-ENGI-owned property data was submitted to NHDES in August 2010. ENGI participated in a site walk in July 2011 with NHDES to review the supplemental investigation locations proposed in the August 2010 Work Plan. **NHDES agreed with the approach and all proposed investigation locations. ENGI submitted a revised Work Plan with revised sampling locations to NHDES in November 2011; the revision was necessary because site access was not granted by the property owners for some of the originally proposed locations. NHDES approved the revised Work Plan, and asked that ENGI notify them when samples were collected on NHDOT's former Johnson and Dix property, which was completed in July 2012.**

LINE
NO.

The New Hampshire Department of Transportation (NHDOT) contacted ENGI in August 2001 and February 2002 regarding possible coal tar-related impacts in a sewer line on a parcel adjacent to the former gas plant. NHDOT is currently conducting groundwater monitoring as part of a Groundwater Management Zone Permit on this parcel. ENGI met with NHDOT and NHDES in January 2003 to review the results of its 2002 site investigation. Limited coal tar impacts were observed in groundwater and subsurface soils at select locations.

On July 15, 2003, NHDES issued a letter to ENGI requesting submission of a schedule and scope of work for a site investigation of the MGP site by mid-September 2003. ENGI proposed a May 2005 date for submission of a Site Investigation Report for the MGP site on Gas Street to NHDES by way of a letter dated October 6, 2003. NHDES agreed to the proposed schedule in their response letter dated October 31, 2003.

ENGI submitted the work plan for the MGP site investigation to NHDES on May 20, 2004. NHDES accepted the work plan on June 16, 2004. The investigation took place between September 2004 and March 2005, and the Site Investigation Report was submitted to NHDES on June 6, 2005. The report indicated that subsurface impacts are present at the MGP, and additional investigation as well as limited remediation will be required. NHDES accepted the report on August 12, 2005, and requested ENGI submit a supplemental scope of work to complete the delineation of MGP-related impacts on and off Site. The document was submitted in November 2005. Site investigation activities at and downgradient of the MGP were conducted in 2006. ENGI submitted an additional supplemental scope of work to further delineate MGP impacts on May 31, 2007 and NHDES subsequently approved the scope on June 5, 2007. ENGI bid the NHDES-approved scope of work in June 2008 and awarded the contract in late July 2008. ENGI met with NHDES at the site in August 2008 to discuss the additional supplemental site investigation activities. The field work took place during October through December 2008, during which time 8 groundwater monitoring wells were installed at 4 off-site locations. The Additional Supplemental Site Investigation Report was submitted to NHDES in September 2009. ENGI met with NHDES to discuss the report findings and strategy for moving forward in October 2009. NHDES issued an approval letter for the Supplemental Site Investigation Report on February 9, 2010. The correspondence approved the report and requested that certain additional activities be completed by ENGI. These requested activities include the following: a) preparation and submission of an Initial Response Action Work Plan to remove approximately 3,500 gallons of liquid and sludge from historic subsurface drip pots and tar wells at the MGP property on Gas Street; b) evaluation of the groundwater conditions in the vicinity of the “Tar Pond” which is depicted on a referenced NHDOT site plan; and c) evaluation of potential indoor air impacts at select locations identified during the additional SSI work.

LINE
NO.

ENGI submitted the Initial Response Work Plan to NHDES in July 2010 to remove approximately 3,500 gallons of liquid and sludge from historic subsurface drip pots. NHDES issued an approval letter for this Work Plan on August 3, 2010 and the work was completed in June 2011. In addition, ENGI submitted a Supplemental Data Collection Work Plan for the additional off-ENGI-owned property investigation activities (items b and c above) to NHDES in August 2010. NHDES approved of the Work Plan on September 16, 2010. **ENGI obtained access to 4 properties in the vicinity of the site in order to conduct the supplemental investigation activities, which included soil, ground water and soil vapor sampling. The investigation work was completed in July 2012.**

When the Exit 13 pond was remediated in 1999, NHDES required that the northern portion remained untouched, allowing for storm water input to the pond, with the knowledge that some contamination remained and may require remediation in the future. In 2006, NHDES requested ENGI address the residual contamination in the pond, and in response, ENGI submitted an Interim Data Collection Report and Scope of Work in May 2006, which was approved in July 2006. This Scope of Work was implemented in 2006 and the results were to be used to prepare the Remedial Action Plan (RAP) which NHDES requested be submitted by August 31, 2006. In July 2006, NHDES extended the deadline for submittal of the RAP to June 30, 2007, to allow ENGI additional time for data collection and design. ENGI submitted an Interim Data Collection Report to NHDES in September 2006, and a Conceptual Remedial Design in March 2007. On March 25, 2009, ENGI submitted a Presumptive Remedy Approval Request to NHDES, in order to allow for the design and implementation of an engineered cap without the need to prepare a RAP. On May 4, 2009, NHDES granted the Presumptive Remedy Approval, and the project moved into the remedial design phase. The proposed remedial work is to be performed on city-owned land and within a NHDOT right-of-way; therefore ENGI is working with these parties to come to agreement on the design features, negotiate access and clarify the responsibilities of the three parties. In April 2010, ENGI met with representatives from NHDES, the City of Concord, and NHDOT to present the proposed remedy, and ENGI submitted the draft design plans to the parties in June 2010. ENGI met with the regulatory permitting agencies in October 2010. The agencies requested that ENGI modify the remedial design to include an upland cap versus a wetland cap to minimize the impacts of the project. The cap was redesigned and ENGI met with the stakeholders in December 2010. At a subsequent meeting in January 2011, the City of Concord requested that the design be further modified to relocate the City's storm water outfall location. ENGI met with the City in March 2011 to present the feasibility evaluation that was conducted for several alternatives, and concluded that the original design was the appropriate design. The City is currently evaluating the draft design plans, and has committed to following up with ENGI following their internal discussions.

LINE
NO.

Semiannual groundwater monitoring at the pond is ongoing, as is recovery of separate phase coal tar from a monitoring well in the vicinity of the pond.

During May 19, 2009 through May 22, 2009, ENGI implemented a NHDES-approved sediment sampling program in the Merrimack River to evaluate potential MGP-related impacts. ENGI met with NHDES in October 2009 to present the results of the sediment investigation, and submitted the sediment sampling data report to NHDES in October 2009. The investigation indicated limited site-related impacts to the shallow near-shore sediments of the Merrimack River. A Site Investigation Addendum Report will be submitted for the river portion of the site in summer 2012; however, based upon the results of the sediment investigation, it is unlikely that remedial actions will be necessary in the river.

5. NEW HAMPSHIRE SITE REMEDIATION PROGRAM PHASE: ENGI submitted an application for a five-year Groundwater Management Zone Permit to the NHDES in April 2002 for the Exit 13 pond. The permit was renewed in October 2007, with the collection of pond surface water samples as an additional condition. Under that permit, groundwater monitoring is expected to be required for the foreseeable future. In addition, as requested by NHDES, ENGI undertook a review of remedial technologies to address the residual contamination remaining in the pond. A conceptual remedial design was submitted to NHDES in March 2007, a Presumptive Remedy Approval was granted by NHDES in May 2009, and the engineered cap design has been drafted. The work will be undertaken pending agreement between the City, NHDOT and ENGI. ENGI met with these parties on several occasions in the last twelve months to discuss the proposed remedy and the required access. The most recent meeting with the City was on March 14, 2011, when the City stated that they would hold internal discussions and contact National Grid when they are ready to reconvene the group.

In July 2003, NHDES requested that ENGI submit a schedule and scope of work for completion of a site investigation of the MGP site. ENGI submitted the scope to NHDES in May 2004 and implemented the work between September 2004 and March 2005. The results of the investigation were documented in the Site Investigation Report, dated June 6, 2005, which was subsequently approved by NHDES. Supplemental investigation activities were performed in 2006. Additional investigation activities were performed in 2008. The additional SSI report was submitted to NHDES in September 2009. In addition, ENGI submitted the Initial Response Work Plan to NHDES in July 2010 to remove approximately 3,500 gallons of liquid and sludge from historic subsurface drip pots. NHDES issued an approval letter for this Work Plan on August 3, 2010 and the work was completed in June 2011. **The NHDES-approved investigation activities were completed in July 2012.**

**ENERGYNORTH NATURAL GAS, INC.**
**d/b/a LIBERTY UTILITIES**

**CONCORD FORMER MGP**

LINE
NO.

6. HISTORY AND CURRENT STATUS OF USE AND OWNERSHIP: The Concord MGP operated from approximately 1850 to 1952, when the natural gas pipeline was extended to Concord. The plant was constructed and operated by predecessors of the Concord Gas Company, which later became known as the Concord Natural Gas Company. By virtue of a merger, ENGI acquired Concord Natural Gas. As has been reported previously by ENGI, it filed a contribution claim in the United States District Court for the District of New Hampshire against the successor to the United Gas Improvement Company. In that claim, ENGI alleged that under the federal Superfund statute, the United Gas Improvement Company exercised control over the operations of the Concord Gas Plant to the extent that the United Gas Improvement Company should be considered an "operator" under the statute. That matter was settled in 1997.

7. LISTING AND STATUS OF INSURANCE AND 3RD PARTY LAWSUITS AND SETTLEMENTS: Numerous confidential settlements with insurance carriers and with one private party have been entered into. *Insurance recovery efforts at the Concord Site are complete.*

***Note: This summary is an overview only and is not intended to be a comprehensive recitation of all relevant information relating to the site and the associated liability.***

**ENERGYNORTH NATURAL GAS, INC.**
**MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS**
**CONCORD MGP - REMEDIATION**
**KEYSPAN PROJECT DEF077**

| LINE NO. | VENDOR | REF NO. | SUBTOTAL EXPENSES | 1108 INSURANCE & THIRD PARTY EXPENSE | 1109 INSURANCE & THIRD PARTY RECOVERIES | TOTAL SUBMITTED |
|---|---|---|---|---|---|---|
| | City of Concord | 7714475 | 600.00 | | | 600.00 |
| | Clean Harbors | SB1196856 | 472.14 | | | 472.14 |
| | Clean Harbors | SB1184641 | 86,480.60 | | | 86,480.60 |
| | Clean Harbors | NH1146942 | 517.11 | | | 517.11 |
| | Clean Harbors | SB1201700 | 2,137.76 | | | 2,137.76 |
| | Clean Harbors | SB1180654 | 2,550.00 | | | 2,550.00 |
| | Clean Harbors | NH1225542 | 550.10 | | | 550.10 |
| | Clean Harbors | NH1250083 | 648.90 | | | 648.90 |
| | Clean Harbors | SB1263315 | 4,740.39 | | | 4,740.39 |
| | GZA GeoEnvironmental, Inc. | 0643831 | 22,685.97 | | | 22,685.97 |
| | GZA GeoEnvironmental, Inc. | 0647642 | 5,441.48 | | | 5,441.48 |
| | GZA GeoEnvironmental, Inc. | 0648605 | 50,187.75 | | | 50,187.75 |
| | GZA GeoEnvironmental, Inc. | 0651155 | 26,794.63 | | | 26,794.63 |
| | GZA GeoEnvironmental, Inc. | 0652443 | 6,795.64 | | | 6,795.64 |
| | GZA GeoEnvironmental, Inc. | 0653551 | 21,276.02 | | | 21,276.02 |
| | GZA GeoEnvironmental, Inc. | 0655554 | 13,359.98 | | | 13,359.98 |
| | GZA GeoEnvironmental, Inc. | 0656957 | 37,600.41 | | | 37,600.41 |
| | McClane | 2011100957 | 182.00 | | | 182.00 |
| | McClane | 2011080875 | 2,038.40 | | | 2,038.40 |
| | McClane | | 1,201.20 | | | 1,201.20 |
| | State of New Hampshire | 7690221 | 1,504.80 | | | 1,504.80 |
| | State of New Hampshire | 7697095 | 298.27 | | | 298.27 |
| | State of New Hampshire | 7705810 | 826.61 | | | 826.61 |
| | State of New Hampshire | 7716409 | 213.06 | | | 213.06 |
| | [redacted] | | | | | |
| | **Total Pool Activity** | | **289,103.22** | **-** | **(31,574.76)** | **257,528.46** |

REDACTED

00000201

**ENERGYNORTH NATURAL GAS, INC.**
**MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS**
**CONCORD POND - REMEDIATION**
**KEYSPAN PROJECT DEF056**

| LINE NO. | VENDOR | REF NO. | SUBTOTAL EXPENSES | INSURANCE & THIRD PARTY EXPENSES | INSURANCE & THIRD PARTY RECOVERIES | TOTAL SUBMITTED |
|---|---|---|---|---|---|---|
| | City of Concord | | 1,440.00 | | | 1,440.00 |
| | Clean Harbors | | 1,015.39 | | | 1,015.39 |
| | Clean Harbors | | 752.30 | | | 752.30 |
| | Clean Harbors | | 846.11 | | | 846.11 |
| | GEI Consultants | 53335 | 4,951.05 | | | 4,951.05 |
| | GEI Consultants | 53488 | 15,286.27 | | | 15,286.27 |
| | GEI Consultants | | 2,851.50 | | | 2,851.50 |
| | GEI Consultants | | 2,663.98 | | | 2,663.98 |
| | GEI Consultants | | 1,214.00 | | | 1,214.00 |
| | GEI Consultants | | 20,509.29 | | | 20,509.29 |
| | GEI Consultants | | 11,237.55 | | | 11,237.55 |
| | GEI Consultants | | 7,168.97 | | | 7,168.97 |
| | GEI Consultants | | 4,254.20 | | | 4,254.20 |
| | GEI Consultants | | 3,704.75 | | | 3,704.75 |
| | GEI Consultants | | 2,927.88 | | | 2,927.88 |
| | GEI Consultants | | 3,828.10 | | | 3,828.10 |
| | State of New Hampshire | 7690222 | 1,760.28 | | | 1,760.28 |
| | [redacted] | | | | | |
| | **Total Pool Activity** | | **86,411.62** | **-** | **(5,173.17)** | **81,238.45** |

00000202

REDACTED

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
CONCORD - LITIGATION
KEYSPAN PROJECT DEF051

| LINE NO. | VENDOR | REF NO. | LEGAL EXPENSES | CONSULTING EXPENSES | REMEDIATION EXPENSES | SETTLEMENT EXPENSES | OTHER EXPENSES | 100 % RECOVERABLE EXPENSES | INSURANCE & THIRD PARTY EXPENSES | INSURANCE & THIRD PARTY RECOVERIES | TOTAL SUBMITTED |
|---|---|---|---|---|---|---|---|---|---|---|---|

# NO ACTIVITY FOR THIS PERIOD

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Total Pool Activity | | | | | | | | | | |

00000203

**ENERGYNORTH NATURAL GAS, INC.**
**d/b/a LIBERTY UTILITIES**
**LACONIA FORMER MGP AND LIBERTY HILL DISPOSAL AREA**

LINE
NO.

1. SITE LOCATION: The former MGP was located on Messer Street in Laconia. Sometime in the early 1950s, during decommissioning of the MGP, wastes from the MGP were disposed of at a location on Liberty Hill Road in Gilford. At the time of the disposal, the property was utilized as a gravel pit, and the disposal reportedly occurred with the permission of the gravel pit owner. The property currently comprises part of a residential neighborhood.

2. DATE SITE WAS FIRST INVESTIGATED: In 1994 and 1995, Public Service Company of New Hampshire (PSNH), one of the former owners and operators of the Laconia Manufactured Gas Plant (MGP), conducted limited site investigations at the plant. In 1996, the New Hampshire Department of Environmental Services (NHDES) sent a "Notification of Site Listing and Request for Site Investigation" for the former Laconia MGP to PSNH and its parent company, Northeast Utilities Services Company (NU), and to EnergyNorth Natural Gas, Inc. (ENGI), another former owner. NHDES designated the site DES #199312038. ENGI and PSNH reached a settlement, reported previously to the New Hampshire Public Utilities Commission (NHPUC), in September 1999. As a result of that settlement, PSNH has had responsibility for the MGP site remediation and interactions with NHDES.

   Per the aforementioned settlement, ENGI retained responsibility for any decommissioning-related liabilities, including off-site disposal. Therefore, in October 2004, ENGI notified NHDES of the possibility that wastes from the MGP were disposed of at a location on Liberty Hill Road sometime in the early 1950s during decommissioning of the plant. Drinking water samples were collected from two residential properties in the vicinity in December 2004, and from three additional properties in June and July 2005 by the NHDES; no MGP-related contaminants were detected. At the request of NHDES, ENGI began preliminary site investigations in July 2005 that culminated in the submission of a Site Investigation Report to NHDES in June 2006. As detailed in the report, MGP-related constituents have been detected in soil and shallow groundwater on four residential properties, and in the abutting brook. The report concluded that further investigations were necessary to determine the extent of the contamination. Additional investigation activities were completed between 2006 and 2009.

3. NATURE AND SCOPE OF SITE CONTAMINATION: Residual materials from the former MGP have been identified at the Laconia MGP site and in the adjacent Winnipesaukee River. Please contact PSNH and refer to PSNH filings with NHDES for complete information on the nature and extent of site contamination at the MGP. Residual materials from the former MGP were disposed of at the Liberty Hill disposal area, and MGP-related constituents have been detected in soil and ground water.

LINE
NO.

4. SUMMARY OF MATERIAL DEVELOPMENTS AND INTERACTIONS WITH ENVIRONMENTAL AUTHORITIES: Based on the settlement with PSNH that has previously been reported to the Commission, ENGI has had no further involvement with the MGP site since the summer of 1999, except with regard to the Liberty Hill disposal area. Please contact PSNH and refer to PSNH filings with NHDES for complete information on material developments and interactions with environmental authorities.

With respect to the Liberty Hill disposal area, in October 2004, ENGI notified NHDES of the possible existence of this disposal site; the site was assigned disposal site number 200411113 by NHDES. NHDES collected drinking water samples from two residential wells in the vicinity in December 2004 and from three additional residential wells in June and July 2005; no MGP-related contaminants were detected. In January 2005, NHDES requested that ENGI conduct a preliminary site investigation on the two residential properties. ENGI submitted a scope of work for the investigation to NHDES on March 2, 2005. The investigation began in July 2005 and was completed in June 2006 with the submission of the Site Investigation Report.

Additional site investigations were conducted in 2006 and summarized in the December 20, 2006 Interim Data Report #2 submitted to NHDES. Based upon the results of the investigations, remediation is required at the site. In response, a Remedial Action Plan (RAP) was submitted to NHDES on February 28, 2007. The RAP presented NHDES with several remedial alternatives to address soil and groundwater contamination at the site. The February 2007 RAP identified soil excavation (to a depth of 3 feet), construction of a containment wall and impermeable cap on the four residential properties purchased by ENGI as the recommended alternative. In September 2007, NHDES responded to the February 2007 RAP and required that ENGI evaluate additional remedial alternatives that included further soil removal. In November 2007, a RAP Addendum was submitted to NHDES. The revised RAP recommended a remedial alternative that included removal of tar-saturated soils to a depth of approximately 45 feet, construction of a containment wall and impermeable cap on the four residential properties owned by ENGI. On February 29, 2008, NHDES issued a letter to ENGI indicating that NHDES had reached a preliminary determination that the remedy recommended in the November 2007 RAP met the NHDES requirements and that a final decision would be reached following a public meeting and comment period.

LINE
NO.

On March 24, 2008, NHDES held a public comment meeting to discuss the recommended alternative and began 30-day public comment period. In April 2008, NHDES received a request to extend the public comment period closing date to May 8, 2008, to allow the Town time to provide technical comment. On June 26, 2008, NHDES issued a letter deferring its final decision on the recommended remedial alternative for the Liberty Hill site pending further data analysis following the development of a scope prepared collaboratively between the Town of Gilford and ENGI. In July and August 2008, technical representatives from ENGI, the Town of Gilford, the Liberty Hill neighborhood and NHDES met twice to discuss the comments provided to NHDES during the public comment period and discuss the scope for additional groundwater modeling activities and limited additional site data collection. The Company submitted Scopes of Work for additional data collection and groundwater modeling to NHDES in September and October 2008, respectively. The field activities were completed between November 2008 and January 2009. Modeling efforts began in late 2008 and were completed in May 2009. In March and May 2009, technical representatives from ENGI, the Town of Gilford, the Liberty Hill neighborhood and NHDES met to discuss the results of the field investigations and the modeling activities. One topic discussed with the technical team was that the modeling results indicate that low-flow pumping would need to be added to the selected remedy meet the remedial goals for the site. On June 30, 2009, NHDES issued a letter to ENGI requesting that a second RAP Addendum be prepared for the site to evaluate the technical changes (mainly the addition of low-flow pumping) to the proposed remedy that resulted from the modeling effort. ENGI submitted the second RAP Addendum to NHDES on August 17, 2009 and presented the findings at a public meeting held in Gilford on September 10, 2009. In October 2009, NHDES hired a third party consultant to review the RAP cost estimates and the results were presented in a report to NHDES in April 2010. In October 2010, NHDES issued a Preliminary Decision on RAP Addendum No. 2, in which NHDES indicated that it did not concur with ENGI's recommended remedial alternative and further recommended the complete removal of coal tar-impacted soils at the site. On January 28, 2011, ENGI submitted a comment letter to NHDES further explaining its rationale for the remedial alternative recommended in RAP Addendum No. 2. **On November 2, 2011 NHDES announced a Final Decision indicating that it did not concur with ENGI's recommended remedial approach and selecting the full removal option as the remedy for the site. On December 2, 2011, ENGI filed an appeal of the NHDES Final Decision with the New Hampshire Waste Management Council. In March 2012, ENGI attended the Pre-Conference Hearing with the Council related to the appeal. A hearing on the matter was scheduled for October 18 and November 15, 2012. On July 26, 2012, the Hearing Officer granted an Assented to Motion to Continue the hearing until a date after January 3, 2013. The Hearing Officer will be determining a new hearing date.**

LINE
NO.

ENGI has also performed numerous other activities requested by NHDES between 2008 and 2011, including remediation of the groundwater seep area near Jewett Brook in accordance with NHDES-approved September 2008 Initial Response Action Plan; evaluation of options for providing financial assurances to NHDES for the site remediation activities; coal tar recovery; semi-annual groundwater and surface water sampling activities; and drinking water well sampling. Groundwater sampling is reported to the NHDES in semi-annual reports. In addition, ENGI developed a Liberty Hill Road site website to assist in updating interested parties.

In conjunction with the Site Investigation work, ENGI has acquired 4 properties on Liberty Hill Road to facilitate remediation activities, and eliminate any potential risk to residents associated with a significant remediation and construction project. The properties were obtained based upon arms-length negotiations, and in one instance to settle potential litigation.

5. NEW HAMPSHIRE SITE REMEDIATION PROGRAM PHASE: Please refer to Item 4.

6. HISTORY AND CURRENT STATUS OF USE AND OWNERSHIP: ENGI is the successor by merger to Gas Service, Inc. (GSI). In 1945, GSI acquired the gas manufacturing assets of PSNH. The Laconia MGP, which began operating in 1894, was included in that transaction. Gas manufacturing took place at the property until 1952, when the MGP was converted to propane. Half of the property is now owned by Robert Irwin and maintained as an open field, and the other half is owned by PSNH, which operates an electric substation on the parcel.

   The Liberty Hill Road parcel on which disposal was believed to have occurred was utilized as a gravel pit at the time of the disposal. It was subdivided in May 1970, and currently constitutes part of a residential subdivision.

7. LISTING AND STATUS OF INSURANCE AND 3RD PARTY LAWSUITS AND SETTLEMENTS: ENGI and PSNH entered into a confidential settlement in 1999. Under this agreement, PSNH took the lead on the MGP site investigation and remediation and all communications with NHDES. ENGI retained responsibility for any decommissioning-related liabilities, including off-site disposal.

   Insurance recovery efforts are complete with respect to the MGP, and numerous confidential settlements have been entered into. In 2003 the United States District Court certified a question to the New Hampshire Supreme Court asking what “trigger of coverage” should be applied to the insurance policies issued by Lloyds of London to ENGI’s predecessor, Gas Service, Inc. In May, 2004 the Supreme Court responded that

LINE
NO.

a "continuous injury-in-fact" trigger should be applied. The federal court conducted a jury trial against Lloyds of London - the only remaining defendant – in October 5, 2004. At the end of that trial the jury returned a verdict in favor of ENGI. Subsequent to the verdict, ENGI and Lloyds of London entered into a confidential settlement.

With respect to Liberty Hill, insurance carriers have been placed on notice of a potential claim, but no litigation has been initiated.

***Note: This summary is an overview only and is not intended to be a comprehensive recitation of all relevant information relating to the site and the associated liability.***

**ENERGYNORTH NATURAL GAS, INC.**
**MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS**
**LIBERTY HILL**
**KEYSPAN PROJECT DEF086**

| LINE NO. | VENDOR | REF NO. | 100 % RECOVERABLE EXPENSES | INSURANCE & THIRD PARTY EXPENSES | INSURANCE & THIRD PARTY RECOVERIES | TOTAL SUBMITTED |
|---|---|---|---|---|---|---|
| | Blue Chip | 01017 | 400.00 | | | 400.00 |
| | Blue Chip Films | 01021 | 237.50 | | | 237.50 |
| | Blue Chip Films | 01030 | 400.00 | | | 400.00 |
| | Clean Harbors | NH1171067 | 481.53 | | | 481.53 |
| | Clean Harbors | SB1291273 | 632.84 | | | 632.84 |
| | GEI Consultants | 53334 | 1,695.37 | | | 1,695.37 |
| | GEI Consultants | 53487 | 1,465.40 | | | 1,465.40 |
| | GEI Consultants | 53659 | 23,024.66 | | | 23,024.66 |
| | GEI Consultants | 053811 | 13,789.36 | | | 13,789.36 |
| | GEI Consultants | 53968 | 9,300.84 | | | 9,300.84 |
| | GEI Consultants | 54155 | 7,266.45 | | | 7,266.45 |
| | GEI Consultants | 54322 | 3,229.53 | | | 3,229.53 |
| | GEI Consultants | 54566 | 1,363.00 | | | 1,363.00 |
| | GEI Consultants | 54,723.00 | 18,423.10 | | | 18,423.10 |
| | GEI Consultants | 54,916.00 | 12,285.65 | | | 12,285.65 |
| | GEI Consultants | 050690 | 14,337.06 | | | 14,337.06 |
| | GEI Consultants | 55159 | 2,319.95 | | | 2,319.95 |
| | GEI Consultants | 55164 | 23,998.15 | | | 23,998.15 |
| | GEI Consultants | 55317 | 3,355.55 | | | 3,355.55 |
| | GZA | 0655625 | 12,029.82 | | | 12,029.82 |
| | McLane | 2011081708 | 728.00 | | | 728.00 |
| | McLane | 2011080874 | 791.70 | | | 791.70 |
| | McLane | 2011120429 | 23,778.00 | | | 23,778.00 |
| | McLane | 2012010761 | 13,463.50 | | | 13,463.50 |
| | McLane | 2012020790 | 8,394.30 | | | 8,394.30 |
| | McLane | 2012031622 | 11,767.35 | | | 11,767.35 |
| | McLane | 2012030856 | 9,257.20 | | | 9,257.20 |
| | McLane | 2012041412 | 6,153.76 | | | 6,153.76 |
| | McLane | 2012050953 | 17,157.88 | | | 17,157.88 |
| | MCLANE GRAF RAULE | 2012030856 | 8,432.65 | | | 8,432.65 |
| | Ostrow & Partners | 071101 | 479.50 | | | 479.50 |
| | Ostrow & Partners | 081101 | 479.50 | | | 479.50 |
| | Ostrow & Partners | 101101 | 323.00 | | | 323.00 |
| | Ostrow & Partners | 91101 | 557.75 | | | 557.75 |
| | Ostrow & Partners | 111101 | 1,262.00 | | | 1,262.00 |
| | Ostrow & Partners | 121101 | 2,598.25 | | | 2,598.25 |
| | Ostrow & Partners | 021201 | 870.75 | | | 870.75 |
| | Ostrow & Partners | 011201 | 1,496.75 | | | 1,496.75 |
| | Ostrow & Partners | 061101 | 557.75 | | | 557.75 |
| | Ostrow & Partners | | 1,340.25 | | | 1,340.25 |
| | Ostrow & Partners | 051201 | 323.00 | | | 323.00 |
| | Ostrow & Partners | 061201 | 557.75 | | | 557.75 |
| | Public Service of New Hampshire | | 11.52 | | | 11.52 |
| | Public Service of New Hampshire | | 12.47 | | | 12.47 |
| | Public Service of New Hampshire | | 11.54 | | | 11.54 |
| | Public Service of New Hampshire | | 13.10 | | | 13.10 |
| | Public Service of New Hampshire | | 11.54 | | | 11.54 |
| | Public Service of New Hampshire | | 12.47 | | | 12.47 |
| | Public Service of New Hampshire | | 11.54 | | | 11.54 |
| | Public Service of New Hampshire | | 12.61 | | | 12.61 |
| | Public Service of New Hampshire | | 11.66 | | | 11.66 |
| | Public Service of New Hampshire | | 12.44 | | | 12.44 |
| | Public Service of New Hampshire | | 11.66 | | | 11.66 |
| | Public Service of New Hampshire | | 12.73 | | | 12.73 |
| | Public Service of New Hampshire | | 11.77 | | | 11.77 |
| | Public Service of New Hampshire | | 12.94 | | | 12.94 |
| | Public Service of New Hampshire | | 23.20 | | | 23.20 |
| | Public Service of New Hampshire | | 48.96 | | | 48.96 |
| | Public Service of New Hampshire | | 11.54 | | | 11.54 |
| | Public Service of New Hampshire | | 12.47 | | | 12.47 |
| | Public Service of New Hampshire | | 11.54 | | | 11.54 |
| | Public Service of New Hampshire | | 12.48 | | | 12.48 |
| | State of New Hampshire | 7690220 | 2,082.70 | | | 2,082.70 |
| | State of New Hampshire | | 3,088.53 | | | 3,088.53 |
| | State of New Hampshire | | 3,013.28 | | | 3,013.28 |
| | **Total Pool Activity** | | **269,281.04** | **-** | **-** | **269,281.04** |

00000209

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
LACONIA - LITIGATION
KEYSPAN PROJECT DEF050

| LINE NO. | VENDOR | REF NO. | LEGAL EXPENSES | CONSULTING EXPENSES | REMEDIATION EXPENSES | SETTLEMENT EXPENSES | OTHER EXPENSES | 100 % RECOVERABLE EXPENSES | INSURANCE & THIRD PARTY EXPENSES | INSURANCE & THIRD PARTY RECOVERIES | TOTAL SUBMITTED |
|---|---|---|---|---|---|---|---|---|---|---|---|

# NO ACTIVITY FOR THIS PERIOD

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Total Pool Activity | | | | | | | | | | | |

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
LIBERTY HILL
KEYSPAN PROJECT DEF087

| LINE NO. | VENDOR | REF NO. | LEGAL EXPENSES | CONSULTING EXPENSES | REMEDIATION EXPENSES | SETTLEMENT EXPENSES | OTHER EXPENSES | 100 % RECOVERABLE EXPENSES | INSURANCE & THIRD PARTY EXPENSES | INSURANCE & THIRD PARTY RECOVERIES | TOTAL SUBMITTED |
|---|---|---|---|---|---|---|---|---|---|---|---|

# NO ACTIVITY FOR THIS PERIOD

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Total Pool Activity | | | | | | | | | | |

00000211

**ENERGYNORTH NATURAL GAS, INC.**
**d/b/a LIBERTY UTILITIES**

**MANCHESTER FORMER MGP**

LINE
NO.

1. SITE LOCATION: 130 Elm Street, Manchester, New Hampshire.

2. DATE SITE WAS FIRST INVESTIGATED: The New Hampshire Department of Environmental Services (NHDES) compiled a list of all former Manufactured Gas Plants (MGPs) in New Hampshire that were not already subject to a site investigation or remediation. In March of 2000, NHDES sent out notice letters to all parties it deemed responsible for the sites. EnergyNorth Natural Gas, Inc. (ENGI) received a "Notification of Site Listing and Request for Site Investigation" for the former Manchester MGP from NHDES, which designated the site DES #200003011.

3. SUMMARY OF MATERIAL DEVELOPMENTS AND INTERACTIONS WITH ENVIRONMENTAL AUTHORITIES:

   - On behalf of ENGI, Harding ESE, Inc. (Harding ESE), submitted a Scoping Phase Field Investigation Scope of Work to NHDES in March 2000.

   - NHDES approved the Scoping Phase Field Investigation Scope of Work in June 2000.

   - During the summer and fall of 2000, ENGI and Harding ESE conducted the Scoping Phase Field Investigation, collecting site background information and soil, groundwater, surface water and sediment samples from the former Manchester MGP and the nearby Merrimack River.

   - On August 31, 2000 an underground tank containing MGP residuals was discovered at the site. As required by NHDES regulations, the tank contents were removed and disposed of subject to a permit from NHDES. Harding ESE, on behalf of ENGI, submitted a summary report to NHDES in January 2001 documenting the response action.

   - ENGI and Harding ESE submitted the Scoping Phase Field Investigation Report to NHDES in February 2001.

   - NHDES provided comments to ENGI and Harding ESE in April 2001 on the Scoping Phase Field Investigation Report and requested a Phase II Investigation Scope of Work.

   - ENGI responded to NHDES' comments on the Scoping Phase Investigation Report and indicated that ENGI planned to solicit bids for the Phase II Scope of Work.

LINE
NO.

- In July 2001, on behalf of ENGI, Harding ESE submitted a Scope of Work to NHDES to fence the ravine near the former Manchester MGP to prevent access to impacted sediments. In October 2001, NHDES accepted ENGI's fence installation plan, but requested clarification on the fence location and signage. In correspondence dated April 3, 2002, ENGI provided proposed language to NHDES for the signs to be attached to the ravine fence. NHDES approved the ravine sign language in April 2002.

- On May 1, 2002, ENGI issued a Request for Proposals to eight environmental consultants for the Phase II Site Investigation and Risk Characterization. ENGI received six proposals for the Phase II work in June 2002.

- In June 2002, the City of Manchester approved the ravine fence location and granted access to City property to install. The work was completed in August 2002.

- URS Consultants were awarded the contract to undertake the next phase of work. A Phase II Site Investigation Scope of Work was submitted in September 2002.

- Phase II field investigations began in the fall of 2002.

- In June 2003, the City of Manchester approved a proposal to construct a minor league ballpark, retail shops, parking garage, hotel and high-rise condominium complex on the Singer Park site, in the same general areas that MGP impacts were detected in ongoing Phase II investigations. Following supplemental ravine investigations during the spring and summer of 2003, the Drainage Ravine Engineering Evaluation was submitted to NHDES in January 2004, and presented four potential remedial alternatives for the ravine, which is located on a portion of Singer Park.

- ENGI had been a regular participant in monthly Singer Park redevelopment meetings with NHDES, the City of Manchester and the various developers from April 2003 until the regular meetings ended on November 15, 2004. ENGI had attended these coordination meetings to ensure that the environmental and construction aspects of the redevelopment were being addressed concurrently and that ENGI avoided incurring costs associated with another entity's contamination.

- ENGI entered into confidential agreements with Manchester Parkside Place (the owner of the ravine property) for access and cleanup of MGP byproducts in the ravine in January 2005.

LINE
NO.

- In January 2005, ENGI submitted a Remedial Design Report to NHDES selecting excavation and off-site disposal of source material and impacted soils as the remedial alternative for the ravine. NHDES approved of this alternative via a letter dated February 7, 2005. Eleven contractors were invited to bid on the ravine remediation in January 2005. The contract was awarded to the low bidder (ENTACT) in February 2005. Remediation of the ravine began in March and was completed in July 2005. A remedial completion report was submitted to NHDES on September 2, 2005.

- ENGI submitted a Phase II Site Investigation Report to NHDES in March 2004. The report concluded that MGP impacts (including impacted soil and groundwater and separate phase coal tar) were present in the subsurface beneath the 130 Elm Street property, portions of Singer Park at depth and the Merrimack River sediment. Further investigations were recommended by ENGI to further assess the nature and extent of this contamination and a work plan proposing those investigations was submitted to NHDES in May 2004 and approved in July 2004. These supplemental investigations were completed and documented in the Supplemental Phase II Investigation Report and the Stage I Ecological Screening Report for the Merrimack River, submitted to NHDES in February and March 2005, respectively. The reports concluded that Remedial Action Plans for the upland and Merrimack River portions of the site were required. On September 15, 2005, NHDES issued a letter accepting the reports and requested ENGI prepare a Remedial Action Plan (RAP) to address impacted sediments in the Merrimack River, as well as MGP-related impacts on the upland portion of the site. Preparation of the RAPs began in August 2006.

- Additional Merrimack River investigations were completed in 2007 and the Remedial Design Report for dredging approximately 9,000 cubic yards of coal tar-impacted sediments from the river was submitted to NHDES on May 11, 2007. ENGI applied for, and was granted, a Dredge and Fill Permit for the remedial dredging from NHDES and the United States Army Corps of Engineers on May 18, 2007. Dredging of the river commenced in June 2007 and was substantially completed by the end of the year. Final site restoration activities associated with the sediment remediation were complete in May 2008. A Remedial Action Implementation Report documenting the sediment remediation activities was submitted to NHDES in May 2008.

- Certain pre-design investigations were completed on the upland portion of the site in 2008/2009. ENGI also completed interim Phase I Corrective Actions at the site, including pilot scale light non-aqueous phase liquid (LNAPL) recovery, pilot scale

LINE
NO.

dense non-aqueous phase (DNAPL) recovery, and design for repair/replacement of a deteriorated portion of the site drainage system located within a known LNAPL area of the site. Limited surface soil removal activities were conducted during the summer/fall of 2008 in an area with detected Upper Concentration Limit exceedences in shallow soils.

- ENGI was issued a Groundwater Management Zone (GMZ) permit No. GWP-200003011-M-001 for the former MGP site on June 15, 2009. The permit establishes a groundwater management zone in the vicinity of the former MGP site with associated notification/groundwater monitoring requirements. **Groundwater monitoring events to support this GMZ permit have been ongoing.**

- ENGI submitted an RAP for the upland portion of the site to NHDES on June 30, 2010. The remedial objectives for the site include control of mobile DNAPL, reduction in contaminant mass (where practicable), and management of residual contamination through the use of administrative controls. The recommended remedial alternative includes removal of the contents of certain subsurface structures where removal is anticipated to provide a reduction in the potential for the further release of DNAPL to the subsurface; NAPL recovery from the subsurface; construction of a barrier wall proximate to the Merrimack River to mitigate potential DNAPL migration; and use of administrative controls to address potential human exposure to residual soil and groundwater contamination. Additional investigation activities were recommended to support the preparation of Design Plans and Construction Specifications following NHDES approval of the RAP and to confirm the appropriateness of certain remedial alternatives recommended in the RAP.

- In Fall 2010, ENGI performed storm drain rehabilitation activities on a deteriorated portion of the site drainage system that is located within a known LNAPL area. This work was performed to mitigate the migration of LNAPL to the Merrimack River via the storm drain system. These activities were mainly completed in late 2010.

- In April 2011, NHDES approved of the upland RAP and requested that ENGI proceed with the additional investigation activities recommended in the June 2010 RAP. In addition, ENGI was contacted by both the developer and condominium association associated with the property directly downgradient of the site regarding potential impacts to the property, as well as the proposed remedy; ENGI met with both parties in early and mid-2011.

LINE
NO.

- **After meeting with the developer of the property located directly downgradient of the site regarding potential impact to the property in September/October 2011, access was obtained to conduct the approved pre-design investigation activities as recommended in the June 2010 RAP. The off-property investigations were substantially completed in December 2011. A meeting was held with NHDES in December 2011 to discuss these results. A Remedial Design Report for the off-site property is currently being finalized.**

- **Additional on-site pre-design investigation activities were conducted in spring 2012 including additional groundwater monitoring, holder foundation test pit excavations, and storm drain analysis. Further investigation activities are planned for the summer 2012 in order to complete the on-site Remedial Design Report.**

**4.** NEW HAMPSHIRE SITE REMEDIATION PHASE: Phase I Site Investigation complete. Phase II Site Investigation complete and supplemental report submitted to NHDES in February 2005. Remedial Action Plan (RAP) for the ravine submitted and approved by NHDES in 2005; remediation of ravine completed in July 2005. Remediation of the river sediment was completed in 2007. A RAP for the upland portion of the site was submitted to NHDES for review on June 30, 2010. NHDES issued its approval of the RAP for the upland portion of the site in a letter dated April 11, 2011. **The Remedial Design Report for the off-site impacts will be submitted in the coming months.**

5. NATURE AND SCOPE OF SITE CONTAMINATION: Residual materials from the former MGP have been identified at the site. These residuals, which include tars and oils, have been found mainly in subsurface soil at discrete locations and in groundwater at the former MGP, as well as in the downgradient Singer Park and river sediment.

6. HISTORY AND CURRENT STATUS OF USE AND OWNERSHIP: The former Manchester MGP is believed to have started producing coal gas in 1852. Gas was produced at the site by the Manchester Gas Company and its predecessors until the MGP was shut down in 1952 when natural gas was supplied to the city via pipeline. ENGI is the successor by merger to the Manchester Gas Company. ENGI continues to own and operate the 130 Elm Street property as an operations center.

7. LISTING AND STATUS OF INSURANCE AND 3RD PARTY LAWSUITS AND SETTLEMENTS: In late 2000, ENGI filed suit against UGI Utilities, Inc. in the United States District Court for the District of New Hampshire, alleging that during much of the early part of the 20th century, a predecessor to that entity “operated” the Manchester Gas Plant, as

LINE
NO.

defined by the Comprehensive Environmental Response, Compensation and Liability Act (commonly referred to as "CERCLA" or "Superfund"). This claim was similar to a claim litigated and ultimately settled by the parties in the late 1990s, related to the former gas plant in Concord, NH. The case went to trial in June 2003 and was settled after 8 days of trial.

Insurance recovery efforts are complete, and confidential settlements have been entered into with all insurance company defendants. An agreement with the last remaining insurance carrier was negotiated in August 2008, under which that carrier paid ENGI's attorneys fees incurred in the litigation. That settlement came about after a ruling from the New Hampshire Supreme Court, in response to a question certified by the United States District Court, on allocation of coverage, and the scope and meaning of NH RSA 491:22-a, as it relates to awards of attorneys fees. EnergyNorth Natural Gas, Inc. v. Certain Underwriters at Lloyds, 156 N.H. 333 (2007). As to allocation, the Court ruled as proposed by the carrier that insurance coverage should be allocated on a *pro rata* basis when multiple policies are triggered by an ongoing event. ENGI had argued for an "all sums" allocation approach in which the insured could choose the policy years from which to obtain indemnity. With respect to attorneys fees, the Court held that " [i]f the insured has obtained rulings that require the excess insurer to indemnify it, the insured has prevailed within the meaning of RSA 491:22-b, and is immediately entitled to recover its reasonable attorneys' fees and costs. Recovery of these fees and costs does not depend on whether, after all is said and done; the excess insurer actually has to pay any indemnification. The insured becomes entitled to the fees and costs once it obtains rulings that demonstrate there is coverage under the excess insurance policy." Under that finding, the insurance carrier was obligated to reimburse attorneys fees even if the *pro rata* allocation analysis resulted in the carrier owning no indemnity.

***Note: This summary is an overview and is not intended to be a comprehensive recitation of all relevant information relating to the site and the associated liability.***

**ENERGYNORTH NATURAL GAS, INC.**
**MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS**
**MANCHESTER - REMEDIATION**
**KEYSPAN PROJECT DEF057**

| LINE NO. | VENDOR | REF NO. | SUBTOTAL EXPENSES | INSURANCE & THIRD PARTY EXPENSE | INSURANCE & THIRD PARTY RECOVERIES | TOTAL SUBMITTED |
|---|---|---|---|---|---|---|
| | Clean Harbors | NH1102485 | 641.48 | | | 641.48 |
| | Clean Harbors | NH1201702 | 245.23 | | | 245.23 |
| | Clean Harbors | SB1226170 | 4,669.45 | | | 4,669.45 |
| | Clean Harbors | NH1219468 | 200.79 | | | 200.79 |
| | Clean Harbors | NH1218836R | 9,685.66 | | | 9,685.66 |
| | Clean Harbors | SB1278817 | 4,318.81 | | | 4,318.81 |
| | Clean Harbors | NH1225529 | 3,750.42 | | | 3,750.42 |
| | Clean Harbors | NH1275853 | 216.30 | | | 216.30 |
| | Colliers International | | 4,800.00 | | | 4,800.00 |
| | EECS | 289 | 5,985.06 | | | 5,985.06 |
| | EECS | 292 | 1,524.26 | | | 1,524.26 |
| | EECS | 294 | 1,766.03 | | | 1,766.03 |
| | EECS | 296 | 2,378.51 | | | 2,378.51 |
| | EECS | 300 | 1,698.84 | | | 1,698.84 |
| | EECS | 298 | 3,476.50 | | | 3,476.50 |
| | ESMI | 1008279 | 566.40 | | | 566.40 |
| | GZA Environmental | 0643887 | 7,154.92 | | | 7,154.92 |
| | GZA Environmental | 0645113 | 4,833.37 | | | 4,833.37 |
| | GZA Environmental | 0647512 | 4,291.46 | | | 4,291.46 |
| | GZA Environmental | 0648849 | 38,814.18 | | | 38,814.18 |
| | GZA Environmental | 0649414 | 97,295.96 | | | 97,295.96 |
| | GZA Environmental | 0652413 | 20,940.35 | | | 20,940.35 |
| | GZA Environmental | 0653160 | 35,270.11 | | | 35,270.11 |
| | GZA Environmental | 0653708 | 25,320.94 | | | 25,320.94 |
| | GZA Environmental | 0655569 | 27,925.28 | | | 27,925.28 |
| | GZA Environmental | 0654301 | 41,160.06 | | | 41,160.06 |
| | GZA Environmental | 0657011 | 17,463.90 | | | 17,463.90 |
| | McLane | 2011081707 | 364.00 | | | 364.00 |
| | McLane | 2011090540 | 6,749.10 | | | 6,749.10 |
| | McLane | 2011100954 | 6,843.20 | | | 6,843.20 |
| | McLane | 2011080872 | 3,989.70 | | | 3,989.70 |
| | McLane | 2011070659 | 4,176.40 | | | 4,176.40 |
| | McLane | 2011120428 | 4,914.80 | | | 4,914.80 |
| | McLane | 2012010759 | 773.50 | | | 773.50 |
| | McLane | 2011110294 | 14,163.00 | | | 14,163.00 |
| | McLane | 2012031621 | 182.00 | | | 182.00 |
| | McLane | 2012020789 | 4,809.20 | | | 4,809.20 |
| | McLane | 2012041121 | 728.00 | | | 728.00 |
| | McLane | 2012050951 | 2,074.80 | | | 2,074.80 |
| | McLane | 2012060826 | 2,402.40 | | | 2,402.40 |
| | State of New Hampshire | 7690224 | 1,490.36 | | | 1,490.36 |
| | State of New Hampshire | 9890-1011 | 89.80 | | | 89.80 |
| | State of New Hampshire | 9890/1-20-12 | 229.64 | | | 229.64 |
| | State of New Hampshire | 9890/4-18-12 | 940.12 | | | 940.12 |
| | T Ford Company, Inc. | 4 | 24,141.23 | | | 24,141.23 |
| | T Ford Company, Inc. | 1380 | 2,837.53 | | | 2,837.53 |
| | T Ford Company, Inc. | 1454 | 59,328.94 | | | 59,328.94 |
| | [redacted] | | | | | |
| | **Total Pool Activity** | | **507,621.99** | **-** | **(65,324.13)** | **442,297.86** |



REDACTED

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
MANCHESTER - LITIGATION
KEYSPAN PROJECT DEF058

| LINE NO. | VENDOR | REF NO. | LEGAL EXPENSES | CONSULTING EXPENSES | REMEDIATION EXPENSES | SETTLEMENT EXPENSES | OTHER EXPENSES | SUBTOTAL EXPENSES | INSURANCE & THIRD PARTY EXPENSES | INSURANCE & THIRD PARTY RECOVERIES | TOTAL SUBMITTED |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | |

# NO ACTIVITY FOR THIS PERIOD

-

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Total Pool Activity | | | - | - | - | - | - | - | - | - | - |

00000219

**ENERGYNORTH NATURAL GAS, INC.**
**d/b/a LIBERTY UTILITIES**

**NASHUA FORMER MGP**

LINE
NO.

1. SITE LOCATION: 38 Bridge Street, Nashua, New Hampshire.

2. DATE SITE WAS FIRST INVESTIGATED: At the end of 1998, the New Hampshire Department of Environmental Services (NHDES) sent a "Notification of Site Listing and Request for Site Investigation" for the former Nashua Manufactured Gas Plant (MGP) to the former plant owners/operators: EnergyNorth Natural Gas, Inc. d/b/a National Grid (ENGI), and Public Service Company of New Hampshire (PSNH) and its parent company, Northeast Utilities Services Company (NU). NHDES designated the site DES #199810022.

3. NATURE AND SCOPE OF SITE CONTAMINATION: Residual materials from the former MGP have been identified at the site and in the adjacent Nashua River. These residuals, which include tars and oils, have been found mainly in subsurface soil at discrete locations, in groundwater, and in localized river sediments.

4. SUMMARY OF MATERIAL DEVELOPMENTS AND INTERACTIONS WITH ENVIRONMENTAL AUTHORITIES:

   - Prior to the time NHDES issued its notice letter to ENGI, the US Environmental Protection Agency (EPA) was remediating contamination (asbestos) at the former Johns Manville plant located adjacent to, and downstream from the 38 Bridge Street property. In the course of that work, EPA detected what it determined to be MGP related residuals in Nashua River sediments containing asbestos. EPA sought reimbursement from ENGI and PSNH of only those incremental additional costs it incurred to dispose of sediments containing MGP related wastes in addition to asbestos. ENGI and PSNH entered into a settlement agreement with the EPA at the end of September 2000. Under the terms of the agreement, each company received a release from liability associated with the so-called Nashua River Superfund Site and contribution protection against future claims associated with that site. The settlement agreement made it clear that EPA does not contend that ENGI or PSNH contributed any asbestos to the Nashua River.

   - In response to the 1998 notice from NHDES, QST Environmental, Inc. (QST, subsequently Environmental Science and Engineering, Inc. (ESE), and later Harding ESE, Inc. (Harding ESE)), submitted a Scoping Phase Field Investigation Scope of Work to NHDES on behalf of ENGI in February 1999.

   - In response to comments from NHDES, QST and ENGI refined the Scope of Work for the Scoping Phase Field Investigation and resubmitted to NHDES in April 1999.

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NO.

- NHDES approved the refined Scoping Phase Field Investigation Scope of Work in May 1999.

- During the summer of 1999, ENGI and QST conducted the Scoping Phase Field Investigation, collecting site background information and soil, groundwater, surface water and sediment samples from the former Nashua MGP and the adjacent Nashua River.

- ENGI and ESE submitted the Scoping Phase Field Investigation Report to NHDES in December 1999.

- NHDES provided comments to ENGI and ESE in February 2000 on the Scoping Phase Field Investigation Report and requested a Phase II Investigation Scope of Work.

- On behalf of ENGI, ESE submitted a Draft Phase II Investigation Work Plan to NHDES in April 2000.

- ENGI and ESE met with the NHDES site manager in April 2000 to discuss the Draft Phase II Investigation Work Plan.

- NHDES provided written comments on the Draft Phase II Investigation Work Plan in June 2000.

- ENGI and ESE met with NHDES in August 2000 to discuss NHDES' comments on the Phase II Work Plan.

- ENGI submitted a letter to NHDES in August 2000 discussing revisions to the Draft Phase II Investigation Work Plan in response to comments from NHDES and PSNH/NU, along with a proposed schedule for implementation of the work.

- NHDES approved the Revised Phase II Work Plan for the site at the end of August 2000.

- NHDES provided comments to ENGI and Harding ESE on the proposed schedule for Phase II Work Plan implementation in September 2000.

- ENGI submitted an addendum to the Phase II Work Plan, including a proposed approach for risk evaluation, to NHDES in November 2000.

LINE
NO.

- Subsequent to meetings and discussions throughout 2000, ENGI and PSNH reached agreement in late 2000 regarding sharing of costs for the remediation work and transfer of management of the remediation work to ENGI.

- Harding ESE implemented the Phase II Work Plan during the fall and winter of 2000/2001. Work entailed a comprehensive field program that included the advancement of river borings and collection of sediment samples as well as the installation of borings and monitoring wells on and off the property.

- NHDES provided comments on the Phase II Work Plan addendum in February 2001.

- Harding ESE responded to NHDES comments on the Phase II Work Plan addendum in March 2001.

- In May 2001, ENGI submitted to NHDES a Draft Site Conceptual Model to assist with finalization of the Phase II Work Plan Addendum and met with NHDES to discuss.

- ENGI and Harding ESE revised the Draft Site Conceptual Model and outlined supplemental field activities to be included in the Phase II Work Plan Addendum and submitted to NHDES in June 2011.

- In July 2001, ENGI and Harding ESE met with NHDES to review the Site Conceptual Model and proposed Phase II supplemental investigation activities.

- ENGI and NHDES met in August 2001 to discuss the overall site objectives.

- In September 2001, Harding ESE, on behalf of ENGI, submitted a Phase IIB Supplemental Site Investigation (SI) Scope of Work to NHDES.

- NHDES provided verbal approval for the Phase IIB Supplemental SI, and Harding ESE initiated the field program on behalf of ENGI in October 2001.

- NHDES provided written approval of the Phase IIB Supplemental SI in October 2001. A modification to the proposed scope of work relating to investigations adjacent to the gas lines was proposed and verbal approval was obtained from NHDES on November 19, 2001.

LINE
NO.

- Property owners north of the Nashua River did not provide access to install monitoring wells proposed in the Phase IIB SOW. Harding ESE completed all on-site work outlined in the Phase IIB SOW in February 2002.

- ENGI received access from PSNH to install Phase IIB monitoring wells west of the site in March 2002.

- Harding ESE installed additional groundwater monitoring wells west of the site in March and sampled all newly installed monitoring wells in April 2002. All work outlined in the Phase IIB SOW was completed except for the proposed monitoring wells north of the Nashua River where access was denied.

- The Phase II Report was submitted to NHDES in February 2003. The report was approved by NHDES in August 2003. At the time of approval, NHDES required ENGI to begin work on the Remedial Action Plan for the site, due in 2004.

- ENGI met with NHDES on November 3, 2003, to review the proposed remedial schedule, which called for the Remedial Action Plan to be submitted in July 2004, and remediation to occur in 2005. NHDES approved the schedule by letter dated December 1, 2003. In that letter they concurred with ENGI's request to divide the site into terrestrial and aquatic portions, to facilitate remediation of sediments concurrent with re-armoring of ENGI's gas mains crossing the river.

- By way of a May 5, 2004 letter, ENGI requested that NHDES waive the Remedial Action Plan (RAP) requirement for the aquatic portion of the site and allow ENGI to proceed with capping sediments in conjunction with gas main rearmoring, which was scheduled for completion in 2004. NHDES approved the request by letter dated May 14, 2004.

- ENGI held pre-application meetings with state and federal agencies (NHDES Wetlands Bureau, United States Army Corps of Engineers, United States Department of Fish and Wildlife, United States Environmental Protection Agency and National Oceanic and Atmospheric Administration) in June 2004. These meetings were held in advance of permit application submission for the capping/rearmoring project, to review the project and expedite the approval process. The application was submitted to these agencies as well as the City of Nashua on July 1, 2004. On July 6, 2004, NHDES deemed the permit application administratively complete. The hearing was closed on July 26, 2004 and the permit was issued in September 2004. The capping and re-armoring was

LINE
NO.

completed in October 2004 and the Remedial Completion Report, submitted to NHDES in January 2005, was subsequently approved.

- In October 2005, ENGI submitted the Terrestrial Remedial Action Plan to NHDES, and the document was deemed complete by NHDES in March 2006. NHDES requested supplemental information to be submitted before ENGI proceeded with remediation, and in 2007 ENGI gathered the requested data.

- In November 2007, ENGI submitted a Workplan for DNAPL Recovery Pilot Test to NHDES and the document was approved by NHDES on November 14, 2007.

- ENGI applied for three permits required for the implementation of the NHDES-approved DNAPL pilot testing activities: Nashua Conservation Commission Permit, Nashua Zoning Board of Appeals Permit and NHDES Dredge and Fill Permit. ENGI attended numerous hearings related to obtaining the permits and obtained the three permits on April 21, 2008, April 23, 2008 and May 31, 2008, respectively.

- In June 2008, ENGI installed six extraction wells for DNAPL recovery pilot testing at the site. ENGI completed the construction of the coal tar recovery system trailer (i.e., the equipment that will be used to pump, collect and temporarily store the coal tar) in December 2008. Trenching for the subsurface piping and final system installation was delayed in late 2008 due to weather. ENGI performed manual DNAPL recovery throughout 2008 and the first three quarters of 2009.

- In Spring 2009, ENGI began trenching and final system installation activities for the DNAPL recovery pilot testing. The trenching, pump installations and system electrical work were completed in July 2009. Electrical service was installed in late August 2009. The system was started up in November 2009 and has been operational since that time. **The system has recovered 198 gallons of DNAPL as of July 2012.**

- In September 2010, ENGI submitted an Installation Summary and DNAPL Recovery Pilot test summary report to NHDES. This report recommended that DNAPL extraction activities continue. In October 2010, a work plan for an off-site groundwater investigation program to support the delineation of a Groundwater Management Zone was submitted to NHDES. This work plan was approved by NHDES in a letter dated November 5, 2010. Access negotiations and environmental permitting for the NHDES-approved investigation were completed in June 2011.

LINE
NO.

- **The NHDES-approved subsurface soil and groundwater investigation program was initiated on September 26, 2011. The goal of this program was to delineate a Groundwater Management Zone for the site, and allow for the filing of a Groundwater Management Permit (GMP). Due to known asbestos in the off-site area to be investigated, ENGI submitted an "In-active Asbestos Disposal Site (ADS) Work Plan"; NHDES approved the asbestos work plan in October 2011. Soil boring and well installation work was performed between October and December 2011. An In-active ADS Site Completion Report was submitted to and accepted by NHDES on May 4, 2012. Groundwater sampling events were conducted in February and May 2012. A meeting to discuss the preliminary results of the Groundwater Management Zone (GMZ) investigation program with NHDES is currently scheduled for August 2012. Pending concurrence of the GMZ findings by NHDES, a GMP is expected to be filed in 2013.**

5. NEW HAMPSHIRE SITE REMEDIATION PROGRAM PHASE: All Supplemental Phase II Site Investigation Work that could be performed (based on property access) has been completed. Phase II Report was submitted to NHDES in February 2003, and approved by NHDES on August 28, 2003. Remediation of the Nashua River sediments was completed in the fall of 2004. A Remedial Action Plan (RAP) for the upland and groundwater was submitted in October 2005, and approved by NHDES in March 2006. DNAPL recovery is on-going.

6. HISTORY AND CURRENT STATUS OF USE AND OWNERSHIP: The Nashua Gas Light Company built the original coal gas facility in 1852 or 1853. In 1889, the Nashua Gas Light Company merged with the Nashua Electric Company to form the Nashua Light, Heat and Power Company (NHLPC). In 1914, the NLHPC merged with the Manchester Traction Light & Power Company, and PSNH acquired the facility in 1926. The MGP facility was upgraded and expanded. In 1945, PSNH divested the gas operations to Gas Service, Inc. Gas production was eliminated in 1952 when natural gas was supplied to the city via pipeline. In 1981, Gas Service, Inc. merged with Manchester Gas Company to form ENGI. ENGI currently owns the majority of the former gas plant property.

7. LISTING AND STATUS OF INSURANCE AND 3RD PARTY LAWSUITS AND SETTLEMENTS: The EPA made a claim against ENGI and PSNH related to the so-called Nashua River Asbestos Site located adjacent to the former MGP. EPA was removing asbestos from the Nashua River, when some was found to be mixed with wastes allegedly from the MGP. Without admitting any facts or liability, by agreement effective December 21, 2000, ENGI resolved EPA's claim in exchange for a payment of

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NO.

$387,371.46, plus interest accrued between settlement and final approval of an administrative consent order by EPA.

ENGI and PSNH have entered into a confidential Site Responsibility and Indemnity Agreement effective as of September 15, 2000, which governs the financial and decision-making responsibilities of the two companies through the remainder of site study and remediation. Under this agreement, ENGI will take the lead on site investigation and remediation.

Numerous, confidential insurance settlements have been entered into. A jury trial commenced against the London Market Insurers and Century Indemnity on November 1, 2005. On November 14, 2005, the jury returned a verdict in favor of EnergyNorth finding that the defendants were obligated to indemnify EnergyNorth for response costs incurred at the site. The Court then awarded ENGI its reasonable costs and attorneys fees to be paid by the defendants. Subsequent to the verdict, the London Market and ENGI entered into a confidential settlement. Century appealed to the First Circuit Court of Appeals in the summer of 2006. However, on the day its brief was due at the First Circuit, Century withdrew its appeal. Because the site has not yet been remediated, the jury was not asked to make a damage determination. Future proceedings will take place after the remedy has been approved by the NHDES to determine the indemnification amounts to be paid by Century. The New Hampshire Supreme Court's ruling and guidance on the proper manner in which costs are to be allocated among insurers (discussed in more detail in the Manchester MGP summary) will be used in the calculation of that figure.

***Note: This summary is an overview only and is not intended to be a comprehensive recitation of all relevant information relating to the site and the associated liability.***

**ENERGYNORTH NATURAL GAS, INC.**
**MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS**
**NASHUA - REMEDIATION**
**KEYSPAN PROJECT DEF054**

| LINE NO. | VENDOR | REF NO. | SUBTOTAL EXPENSES | INSURANCE & THIRD PARTY EXPENSE | INSURANCE & THIRD PARTY RECOVERIES | TOTAL |
|---|---|---|---|---|---|---|
| | Clean Harbors | SB1113870 | 3,090.76 | | | 3,090.76 |
| | Clean Harbors | SB1194034R | 7,254.81 | | | 7,254.81 |
| | Clean Harbors | SB1287793 | 7,688.26 | | | 7,688.26 |
| | Environmental Staff Project Time | | 9,640.35 | | | 9,640.35 |
| | GZA Environmental | 0648178 | 26,662.49 | | | 26,662.49 |
| | GZA Environmental | 0650594 | 8,053.45 | | | 8,053.45 |
| | GZA Environmental | 0652228 | 900.12 | | | 900.12 |
| | GZA Environmental | 0649755 | 25,729.49 | | | 25,729.49 |
| | GZA Environmental | 0656883 | 6,749.56 | | | 6,749.56 |
| | Innovative Engineering | 9508 | 2,570.41 | | | 2,570.41 |
| | Innovative Engineering | 9554 | 2,991.23 | | | 2,991.23 |
| | Innovative Engineering | 9580 | 4,792.00 | | | 4,792.00 |
| | Innovative Engineering | 9697 | 11,535.33 | | | 11,535.33 |
| | Innovative Engineering | 9777 | 25,278.30 | | | 25,278.30 |
| | Innovative Engineering | 9837 | 104,095.50 | | | 104,095.50 |
| | Innovative Engineering | 9930 | 27,332.14 | | | 27,332.14 |
| | Innovative Engineering | 10045 | 8,145.00 | | | 8,145.00 |
| | Innovative Engineering | 9986 | 52,610.63 | | | 52,610.63 |
| | Innovative Engineering | 10092 | 3,875.00 | | | 3,875.00 |
| | Innovative Engineering | 10183 | 2,815.00 | | | 2,815.00 |
| | Innovative Engineering | 10245 | 29,960.98 | | | 29,960.98 |
| | McLane | 2011050844 | 400.40 | | | 400.40 |
| | McLane | 2011070658 | 4,841.20 | | | 4,841.20 |
| | McLane | 2011081706 | 109.20 | | | 109.20 |
| | McLane | 2011060321 | 6,191.90 | | | 6,191.90 |
| | McLane | | 2,256.80 | | | 2,256.80 |
| | McLane | 2011060321 | 6,042.40 | | | 6,042.40 |
| | McLane | 201108071 | 509.60 | | | 509.60 |
| | McLane | 2012030857 | 582.40 | | | 582.40 |
| | McLane | 2012031620 | 655.20 | | | 655.20 |
| | McLane | 2012041120 | 728.00 | | | 728.00 |
| | McLane | 2012050949 | 728.00 | | | 728.00 |
| | McLane | | 1,929.20 | | | 1,929.20 |
| | State of New Hampshire | 7690223 | 439.56 | | | 439.56 |
| | State of New Hampshire | 8323/1-20-12 | 298.27 | | | 298.27 |
| | State of New Hampshire | 8323/4-18-12 | 1,917.40 | | | 1,917.40 |
| | [redacted] | | | | | |
| | **Total Pool Activity** | | **399,400.34** | **-** | **(2,989.64)** | **396,410.70** |



REDACTED

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
NASHUA - LITIGATION
KEYSPAN PROJECT DEF049

| LINE NO. | VENDOR | REF NO. | 1101 LEGAL EXPENSES | 1102 CONSULTING EXPENSES | 1105 REMEDIATION EXPENSES | 1106 SETTLEMENT EXPENSES | 1107 OTHER EXPENSES | 100 % RECOVERABLE EXPENSES | INSURANCE & THIRD PARTY EXPENSES | INSURANCE & THIRD PARTY RECOVERIES | TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | |
| | Total Pool Activity | | - | - | - | - | - | - | - | - | - |

# NO ACTIVITY FOR THIS PERIOD

**ENERGYNORTH NATURAL GAS, INC.**
**d/b/a LIBERTY UTILITIES**

**DOVER FORMER MGP**

LINE
NO.

1. SITE LOCATION: Intersection of Cocheco Street and Portland Street, Dover, New Hampshire.

2. DATE SITE WAS FIRST INVESTIGATED: In 1999, NHDES sent notice letters to current and former site owners and operators including: Public Service Company of New Hampshire (PSNH) and its parent company, Northeast Utilities (NU).; EnergyNorth Natural Gas, Inc. (ENGI); Northern Utilities, Inc.; and Central Vermont Public Service Company (CVPS). It is the company's understanding that NHDES sent a notice to the current site owner, Estelle Maglaras, earlier. NHDES designated the site DES #198401047.

3. NATURE AND SCOPE OF SITE CONTAMINATION: According to the August 2002 Supplemental Site Investigation Report, the evaluation of the nature and extent of MGP impacts to the site has been completed. Residual materials from the former MGP have been identified at the site and in the adjacent Cocheco River. These residuals, which include tars, oils, and purifier waste, have been found in surface soil, subsurface soil, groundwater, and river sediment.

4. SUMMARY OF MATERIAL DEVELOPMENTS AND INTERACTIONS WITH ENVIRONMENTAL AUTHORITIES:

   - During late 1999 and early 2000, PSNH/NU took the lead on preparation of a Site Investigation Report. PSNH/NU submitted the report to NHDES and the other potentially responsible parties (PRPs) in February 2000.

   - The PRPs held meetings and discussions during 2000 regarding site responsibility and liability.

   - Following an October meeting between NHDES, PSNH/NU, ENGI, and CVPS, Metcalf & Eddy, Inc. (M&E) submitted a Supplemental Site Investigation Work Plan to NHDES on behalf of PSNH/NU, ENGI, and CVPS to NHDES in December 2000.

   - NHDES provided written comments on the Supplemental Site Investigation Work Plan in April, 2001.

   - M&E submitted a letter response to NHDES comments on the Work Plan to NHDES in early June 2001.

LINE
NO.

- NHDES approved the Supplemental Site Investigation Work Plan and letter addendum in late June 2001.

- PSNH/NU, in conjunction with CVPS and ENGI, submitted the M&E Supplemental Site Investigation Report to the DES on August 9, 2002.

- Since 2002, PSNH has conducted work at the site without ENGI's active involvement. NHDES is aware of the situation. **Please contact PSNH or refer to PSNH/NU filings with NHDES for complete information on material developments and interactions with environmental authorities.**

5. NEW HAMPSHIRE SITE REMEDIATION PHASE: Supplemental Site Investigation completed. Please contact PSNH or NHDES for current status.

6. HISTORY AND CURRENT STATUS OF USE AND OWNERSHIP: ENGI is the successor by merger to Gas Service, Inc (GSI). In 1945, GSI acquired the gas manufacturing assets of PSNH. The Dover MGP, which began operation in 1850, was included in that transaction. GSI operated the Dover MGP until 1956, when it was sold to Allied New Hampshire Gas Company (Allied). Approximately 10 months after that sale, the MGP was shut down when natural gas arrived in Dover. Allied merged into Northern Utilities in 1969, and Northern Utilities continued to own the property until 1978. At that time, the property was sold to Estelle Maglaras, the current owner. The majority of the property is used by the Maglaras family as a marina and boatyard. Northern Utilities, Inc. maintains a regulator station on a small portion of the former MGP property.

7. LISTING AND STATUS OF INSURANCE AND 3RD PARTY LAWSUITS AND SETTLEMENTS: Mediation between PSNH, ENGI, CVPS and Northern Utilities for allocation was undertaken in the fall of 2001 but was not successful. Since that time, PSNH reached a confidential settlement and allocation with CVPS, and has taken the lead on site investigation and remediation activities. Please contact PSNH or refer to PSNH/NU filings with NHDES for complete information on material developments. PSNH and ENGI have attempted to negotiate an allocation but thus far have been unsuccessful.

   Insurance recovery efforts are complete, and resulted in several confidential settlements as well as a judgment in favor of coverage. Trial was conducted in the United States District Court in February, 2005. At the close of the defendant's case, the court directed a verdict in ENGI's favor on the issue of coverage determining that the defendant is liable for environmental costs related to the site. In May, 2005, the court ordered Century Indemnity to reimburse ENGI's attorneys' fees and costs associated with the litigation. In June 2005, the Court issued an Amended Judgment awarding fees to ENGI. Century appealed the Amended Judgment and oral argument was heard in January 2006. Century's appeal was

LINE
NO.

denied by the Court in June 2006, and ENGI was ultimately awarded its attorneys fees associated with that appeal.

***Note: This summary is an overview and is not intended to be a comprehensive recitation of all relevant information relating to the site and the associated liability.***

**ENERGYNORTH NATURAL GAS, INC.**
**MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS**
**SITE NAME: DOVER - REMEDIATION**
**KEYSPAN PROJECT DEF059**

| LINE NO. | VENDOR | REF NO. | 1101 LEGAL EXPENSES | 1102 CONSULTING EXPENSES | 1105 REMEDIATION EXPENSES | 1106 SETTLEMENT EXPENSES | 1107 OTHER EXPENSES | 100 % RECOVERABLE EXPENSES | 1108 INSURANCE & THIRD PARTY EXPENSE | INSURANCE & THIRD PARTY RECOVERIES | TOTAL SUBMITTED |
|---|---|---|---|---|---|---|---|---|---|---|---|

# NO ACTIVITY FOR THIS PERIOD

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Total Pool Activity** | | | | | | | | | | |

00000232

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
DOVER - LITIGATION
KEYSPAN PROJECT DEF060

| LINE NO. | VENDOR | REF NO. | LEGAL EXPENSES | CONSULTING EXPENSES | REMEDIATION EXPENSES | SETTLEMENT EXPENSES | OTHER EXPENSES | 100 % RECOVERABLE EXPENSES | INSURANCE & THIRD PARTY EXPENSES | INSURANCE & THIRD PARTY RECOVERIES | TOTAL SUBMITTED |
|---|---|---|---|---|---|---|---|---|---|---|---|

# NO ACTIVITY FOR THIS PERIOD

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Total Pool Activity | | - | - | - | - | - | - | - | - | - |

00000233

**ENERGYNORTH NATURAL GAS, INC.**
**d/b/a LIBERTY UTILITIES**

**KEENE FORMER MGP**

LINE
NO.

1. SITE LOCATION: 207 and 227 Emerald Street, Keene, New Hampshire.

2. DATE SITE WAS FIRST INVESTIGATED: Information on site investigation activities comes from reports prepared by Public Service Company of New Hampshire (PSNH). It is apparent the New Hampshire Department of Environmental Services (NHDES) first investigated Mill Creek adjacent to the former Keene Manufactured Gas Plant (MGP) in 1986. PSNH, a former owner and operator, and its parent company, Northeast Utilities Service Company (NU), conducted several site assessments of the former MGP during the early and mid-1990s. PSNH/NU completed a Site Investigation in 1996 in response to a notice letter from the NHDES, which designated the site DES # 199412009. PSNH/NU has had responsibility for site management and interactions with NHDES since that time. Although it does not appear to have been actively involved in the site study, Keene Gas Corporation (KGC) received a notice letter from NHDES in January 1999. In response to a request from PSNH/NU, NHDES sent a notice letter to EnergyNorth Natural Gas, Inc. (ENGI) in April 2001. ENGI responded to the NHDES on April 27, 2001, indicating that it would continue to coordinate with PSNH and that it was evaluating its potential liability, if any, at the site.

3. NATURE AND SCOPE OF SITE CONTAMINATION: Residual materials from the former MGP have been identified at the site in sediments of the adjacent Mill Creek and Ashuelot River. Removal of impacted sediment areas constituting readily apparent harm and restoration of the creek bed and portions of the river bed is the likely remedial alternative for the aquatic portion of the site.

4. SUMMARY OF MATERIAL DEVELOPMENTS AND INTERACTIONS WITH ENVIRONMENTAL AUTHORITIES: ENGI entered into a confidential agreement with PSNH relative to the development and execution of a Remedial Action Plan (RAP) for the aquatic portion of the site in January 2005. Subsequently, in March 2005, ENGI and PSNH/NU submitted a Scope of Work for the ecological evaluation of the Ashuelot River Sediments to NHDES, and met with NHDES on April 25, 2005 to discuss the conceptual RAP (consisting of sediment removal and stream bed restoration) for Mill Creek/Ashuelot River. NHDES approved the scope of the ecological evaluation, and it was conducted in 2005. In February 2006, PSNH submitted a scope of work for a supplemental investigation of the Ashuelot River, which was approved by NHDES in April 2006. This work was completed and in February 2007 NHDES requested the preparation of a Remedial Action Plan (RAP) for Mill Creek and a portion of the Ashuelot River. NHDES files indicate that PSNH submitted the RAP in 2008 and completed permitting and obtaining access from private property owners for the Mill Creek and Ashuelot River remediation activities in 2010. Subsequently, a remedial contractor was a selected, and

LINE
NO.

Phase II RAP implementation is underway. According to NHDES files, remedial actions in the Mill Creek and Ashuelot River continued in late 2011/2012.

5. NEW HAMPSHIRE SITE REMEDIATION PROGRAM PHASE: Remediation of the terrestrial portion of the site was completed by PSNH/NU in 2004/2005. An ecological risk assessment in support of a Remedial Action Plan for the Ashuelot River and Mill Creek portions of the site was conducted jointly by ENGI and PSNH/NU in 2005. A supplemental investigation of the Ashuelot River to support the preparation of a Remedial Action Plan (RAP) was completed in 2007 and NHDES has requested PSNH/NU submit the RAP for Mill Creek and portions of the Ashuelot River in 2007. NHDES files indicate that the RAP was submitted by PSNH in 2008 and that NHDES commented and approved the Phase II RAP. NHDES and other public information sources indicate that remedial and wetland permitting is complete, necessary approvals and site access agreements with impacted landowners are complete, a remedial contractor has been selected, and Phase II RAP implementation is on-going. PSNH has taken the lead on investigation at this Site, and has conducted this work without ENGI's active involvement. NHDES is aware of the situation. **Please contact PSNH or refer to PSNH/NU filings with NHDES for complete information on material developments and interactions with environmental authorities.**

6. HISTORY AND CURRENT STATUS OF USE AND OWNERSHIP: Given its status at the site, ENGI has not yet conducted a thorough evaluation of its history. It is known that the plant became operational in approximately 1860 and operated as a manufactured gas plant until 1952, after which it was converted to butane and later to propane. Gas Service, Inc., a predecessor of ENGI, owned the former MGP between October 1945 and its closure in 1952. Gas Service continued to own the property until it was sold to KGC in 1979. KGC continues to operate a propane-air plant at the site. Please contact PSNH or refer to PSNH/NU filings with NHDES for complete information on site history, use and ownership.

7. LISTING AND STATUS OF INSURANCE AND 3RD PARTY LAWSUITS AND SETTLEMENTS: Insurance recovery claims are underway, and confidential settlements have been entered into with all but one defendant. The case is currently stayed. Trial had been scheduled for October 2006 against the sole remaining insurance company defendant, Century Indemnity, however that trial was put off while awaiting a ruling on an issue of law in the Manchester MGP litigation by the New Hampshire Supreme Court. The Supreme Court has since ruled on the appropriate method of allocating indemnification obligations among multiple insurers and the applicability of the New Hampshire attorneys fees statute, RSA 491:22-a, which is relevant to the Keene case. In

LINE
NO.

that case, EnergyNorth Natural Gas, Inc. v. Certain Underwriters at Lloyds, 156 N.H. 333 (2007), the Court ruled as proposed by the carrier that insurance coverage should be allocated on a *pro rata* basis when multiple policies are triggered by an ongoing event. ENGI had argued for an "all sums" allocation approach in which the insured could choose the policy years from which to obtain indemnity. With respect to attorneys fees, the Court held that " [i]f the insured has obtained rulings that require the excess insurer to indemnify it, the insured has prevailed within the meaning of RSA 491:22-b, and is immediately entitled to recover its reasonable attorneys' fees and costs. Recovery of these fees and costs does not depend on whether, after all is said and done, the excess insurer actually has to pay any indemnification. The insured becomes entitled to the fees and costs once it obtains rulings that demonstrate there is coverage under the excess insurance policy." Under that finding, the insurance carrier was obligated to reimburse attorneys fees even if the *pro rata* allocation analysis resulted in the carrier owning no indemnity.

ENGI intervened in Docket DE 98-123, the proceeding in which the Commission considered the proposed transfer of operating assets from Keene Gas Corporation (KGC) to New Hampshire Gas Corporation (NHGC). ENGI opposed the proposed transfer because it was concerned that the transfer was likely to create a significant, and possibly insurmountable, obstacle to the potential for KGC customers to share in responsibility for any costs associated with environmental liabilities at the Keene MGP site. At the time, ENGI had not been named as a potentially responsible party for the Keene MGP site, nor had it been notified by any PRP of any claimed liability for the site. Nevertheless, ENGI was aware of the possibility that it would receive such a notice at some point in the future. In the KGC/NHGC proceeding, ENGI proposed that the Commission condition any approval of the proposed transfer on NHGC's willingness to assume responsibility for KGC's liability with regard to the site. The Commission ultimately approved the transfer of assets without imposing such a condition, finding among other things that liability for environmental contamination at the Keene MGP site remained speculative at that time and that assignment of any such liability to various parties was not appropriate for determination by the Commission.

***Note: This summary is an overview only and is not intended to be a comprehensive recitation of all relevant information relating to the site and the associated liability.***

**ENERGYNORTH NATURAL GAS, INC.**
**MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS**
**KEENE - REMEDIATION**
**KEYSPAN PROJECT DEF055**

| LINE NO. | VENDOR | REF NO. | SUBTOTAL EXPENSES | INSURANCE & THIRD PARTY EXPENSE | INSURANCE & THIRD PARTY RECOVERIES | TOTAL SUBMITTED |
|---|---|---|---|---|---|---|
| | Environmental Staff Project Time | | 487.69 | | | 487.69 |
| | **Total Pool Activity** | | **487.69** | | | **487.69** |

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
KEENE - LITIGATION
KEYSPAN PROJECT DEF071

| LINE NO. | VENDOR | REF NO. | LEGAL EXPENSES | CONSULTING EXPENSES | REMEDIATION EXPENSES | SETTLEMENT EXPENSES | OTHER EXPENSES | 100 % RECOVERABLE EXPENSES | INSURANCE & THIRD PARTY EXPENSES | INSURANCE & THIRD PARTY RECOVERIES | TOTAL SUBMITTED |
|---|---|---|---|---|---|---|---|---|---|---|---|

# NO ACTIVITY FOR THIS PERIOD

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Total Pool Activity | | | | | | | | | | |

00000238

**ENERGYNORTH NATURAL GAS, INC.**
**MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS**
**GENERAL EXPENSES**
**KEYSPAN PROJECT DEF064**

| LINE NO. | VENDOR | REF NO. | SUBTOTAL EXPENSES | INSURANCE & THIRD PARTY EXPENSE | INSURANCE & THIRD PARTY RECOVERIES | TOTAL SUBMITTED |
|---|---|---|---|---|---|---|
| | Curry Printing | 197116 | 1,302.84 | | | 1,302.84 |
| | EECS | 294 | 1,217.00 | | | 1,217.00 |
| | EECS | 296 | 974.00 | | | 974.00 |
| | EECS | 298 | 3,531.00 | | | 3,531.00 |
| | EECS | 300 | 437.00 | | | 437.00 |
| | Environmental Staff Time | | 76,173.48 | | | 76,173.48 |
| | GZA | 0647698 | 6,480.00 | | | 6,480.00 |
| | McLane | 2011100955 | 409.50 | | | 409.50 |
| | McLane | 2011031035 | 40.00 | | | 40.00 |
| | McLane | 2011060325 | 72.80 | | | 72.80 |
| | McLane | 2011050847 | 45.50 | | | 45.50 |
| | McLane | 2011020723 | 1,562.50 | | | 1,562.50 |
| | Pro Unlimited (refer to spreadsheet) | | 71.25 | | | 71.25 |
| | Pro Unlimited (refer to spreadsheet) | | 42.75 | | | 42.75 |
| | Pro Unlimited (refer to spreadsheet) | | 57.72 | | | 57.72 |
| | Pro Unlimited (refer to spreadsheet) | | 228.72 | | | 228.72 |
| | Pro Unlimited (refer to spreadsheet) | | 72.15 | | | 72.15 |
| | Pro Unlimited (refer to spreadsheet) | | 202.02 | | | 202.02 |
| | Pro Unlimited (refer to spreadsheet) | | 114.00 | | | 114.00 |
| | [redacted] | | | | | |
| | **Total Pool Activity** | | **93,034.23** | **-** | **(14,067.63)** | **78,966.60** |

REDACTED

**III DELIVERY TERMS AND CONDITIONS**

**NHPUC NO. 7 - GAS**
**LIBERTY UTILITIES**

**Proposed First Revised Page 155**
**Superseding Original Revised Page 155**

ATTACHMENT B
Schedule of Administrative Fees and Charges

| | | | |
|---|---|---|---|
| I. | Supplier Balancing Charge: | $0.19 per MMBtu of Daily Imbalance Volumes* | |
| II. | Capacity Mitigation Fee | 15% of the Proceeds from the Marketing of Capacity for Mitigation. | |
| III. | Peaking Demand Charge | $18.62 MMBTU of Peak MDQ. | |
| IV. | Company Allowance Calculation (per Schedule 25) | | |
| | | 138,409,150 | Total Sendout - Therms Jul-2011 - Jun-2012 |
| | | 136,259,218 | Total Throughput - Therms Jul-2011 - Jun-2012 |
| | | 2,149,932 | Variance (Sendout - Throughput) |
| | Company Allowance Percentage 2012-13 | 1.6% | Variance / Total Sendout |

* The difference between the ATV and the recalculated ATV adjusted for actual degree days.

**ENERGY NORTH NATURAL GAS, INC.**

**Calculation of Supplier Balancing Charge**
**2012-13**

**Rate:** **$0.19** **/MMBtu**

| | Rate | Volume | Total |
|---|---|---|---|
| Injection Cost | $0.0087 | **540,530** | $4,703 |
| Withdrawal Cost | $0.0087 | **385,530** | $3,354 |
| Delivery Rate | $0.0506 | 385,530 | $19,519 |
| FTA Demand Charge | $0.2791 | 385,530 | $107,605 |
| FTA Commodity Charge | $0.1091 | 385,530 | $42,061 |
| | | Total Cost | $177,243 |
| | | Absolute Value of the Sendout Error | **926,061** MMBtu |
| | | Rate | $ 0.19 /MMBTU |

NOTES: See Tennessee Gas Pipeline Tariff Pages in Tab 6

| | | |
|---|---|---|
| TGP FSMA Injection Charge | $0.0087 | / MMBtu |
| TGP FSMA Withdrawal Charge | $0.0087 | / MMBtu |
| TGP FSMA Deliverability Charge | $1.54 | / MMBtu per month |
| | $0.0506 | / MMBtu per day |
| TGP Z4-6 Demand Charge | $8.49 | / MMBtu per month |
| | $0.2791 | / MMBtu per day |
| TGP Z4-6 Commodity Charge | $0.1091 | / MMBtu |

**EnergyNorth Natural Gas Inc.**

**Calculation of Supplier Balancing Charge**
**2012-13**
## Estimated Monthly Imbalances

| Date | Forecasted DD | Actual DD | Forecaster Error DD | Forecasted Sendout (MMBtu) | Actual Sendout (MMBtu) | Sendout Error (MMBtu) | Abs.Value Sendout Error (MMBtu) | Injections (MMBtu) | Withdrawals (MMBtu) |
|---|---|---|---|---|---|---|---|---|---|
| Nov | 611 | 598 | 13 | 1,102,514 | 1,086,584 | 15,931 | 99,262 | 57,596 | 41,666 |
| Dec | 948 | 922 | 26 | 1,790,147 | 1,746,397 | 43,750 | 144,712 | 94,231 | 50,481 |
| Jan | 1,149 | 1,105 | 44 | 2,128,369 | 2,054,331 | 74,039 | 171,635 | 122,837 | 48,798 |
| Feb | 947 | 916 | 31 | 1,775,887 | 1,723,724 | 52,164 | 92,548 | 72,356 | 20,192 |
| Mar | 660 | 652 | 8 | 1,256,941 | 1,244,962 | 11,979 | 167,707 | 89,843 | 77,864 |
| Apr | 495 | 505 | -10 | 922,785 | 936,802 | -14,017 | 109,331 | 47,657 | 61,674 |
| May | 211 | 222 | -11 | 477,671 | 486,721 | -9,049 | 51,828 | 21,389 | 30,439 |
| Jun | 47 | 77 | -30 | 315,837 | 321,740 | -5,903 | 7,477 | 787 | 6,690 |
| Jul | 0 | 0 | 0 | 268,914 | 268,914 | 0 | 0 | 0 | 0 |
| Aug | 0 | 2 | -2 | 282,306 | 283,281 | -976 | 976 | 0 | 976 |
| Sep | 72 | 72 | 0 | 315,766 | 315,766 | 0 | 8,245 | 4,122 | 4,122 |
| Oct | 408 | 418 | -10 | 681,695 | 694,613 | -12,918 | 72,340 | 29,711 | 42,629 |
| **Total** | **5,548** | **5,489** | **59** | **11,318,834** | **11,163,834** | **155,000** | **926,061** | **540,530** | **385,530** |

**EnergyNorth Natural Gas Inc.**

**Calculation of Supplier Balancing Charge**
**2011-12**
**Estimated Daily Imbalances**

| Date | Forecasted MAN HDD | Actual MAN HDD | Forecaster Error MAN HDD | Forecasted Sendout (MMBtu) | Actual Sendout (MMBtu) | Sendout Error (MMBtu) | Abs.Value Sendout Error (MMBtu) | Injections (MMBtu) | Withdrawals (MMBtu) |
|---|---|---|---|---|---|---|---|---|---|
| Apr 1, 11 | 29 | 28 | 1 | 48,281 | 46,879 | 1,402 | 1,402 | 1,402 | 0 |
| Apr 2, 11 | 27 | 22 | 5 | 45,477 | 38,469 | 7,008 | 7,008 | 7,008 | 0 |
| Apr 3, 11 | 26 | 23 | 3 | 44,075 | 39,870 | 4,205 | 4,205 | 4,205 | 0 |
| Apr 4, 11 | 21 | 25 | -4 | 37,067 | 42,674 | -5,607 | 5,607 | 0 | 5,607 |
| Apr 5, 11 | 23 | 25 | -2 | 39,870 | 42,674 | -2,803 | 2,803 | 0 | 2,803 |
| Apr 6, 11 | 23 | 26 | -3 | 39,870 | 44,075 | -4,205 | 4,205 | 0 | 4,205 |
| Apr 7, 11 | 21 | 23 | -2 | 37,067 | 39,870 | -2,803 | 2,803 | 0 | 2,803 |
| Apr 8, 11 | 18 | 22 | -4 | 32,862 | 38,469 | -5,607 | 5,607 | 0 | 5,607 |
| Apr 9, 11 | 11 | 13 | -2 | 23,050 | 25,854 | -2,803 | 2,803 | 0 | 2,803 |
| Apr 10, 11 | 12 | 10 | 2 | 24,452 | 21,649 | 2,803 | 2,803 | 2,803 | 0 |
| Apr 11, 11 | 5 | 0 | 5 | 14,640 | 7,632 | 7,008 | 7,008 | 7,008 | 0 |
| Apr 12, 11 | 13 | 11 | 2 | 25,854 | 23,050 | 2,803 | 2,803 | 2,803 | 0 |
| Apr 13, 11 | 23 | 22 | 1 | 39,870 | 38,469 | 1,402 | 1,402 | 1,402 | 0 |
| Apr 14, 11 | 17 | 17 | 0 | 31,460 | 31,460 | 0 | 0 | 0 | 0 |
| Apr 15, 11 | 22 | 25 | -3 | 38,469 | 42,674 | -4,205 | 4,205 | 0 | 4,205 |
| Apr 16, 11 | 18 | 20 | -2 | 32,862 | 35,665 | -2,803 | 2,803 | 0 | 2,803 |
| Apr 17, 11 | 14 | 17 | -3 | 27,255 | 31,460 | -4,205 | 4,205 | 0 | 4,205 |
| Apr 18, 11 | 16 | 15 | 1 | 30,059 | 28,657 | 1,402 | 1,402 | 1,402 | 0 |
| Apr 19, 11 | 20 | 21 | -1 | 35,665 | 37,067 | -1,402 | 1,402 | 0 | 1,402 |
| Apr 20, 11 | 21 | 22 | -1 | 37,067 | 38,469 | -1,402 | 1,402 | 0 | 1,402 |
| Apr 21, 11 | 24 | 23 | 1 | 41,272 | 39,870 | 1,402 | 1,402 | 1,402 | 0 |
| Apr 22, 11 | 20 | 19 | 1 | 35,665 | 34,264 | 1,402 | 1,402 | 1,402 | 0 |
| Apr 23, 11 | 16 | 22 | -6 | 30,059 | 38,469 | -8,410 | 8,410 | 0 | 8,410 |
| Apr 24, 11 | 13 | 6 | 7 | 25,854 | 16,042 | 9,812 | 9,812 | 9,812 | 0 |
| Apr 25, 11 | 13 | 14 | -1 | 25,854 | 27,255 | -1,402 | 1,402 | 0 | 1,402 |
| Apr 26, 11 | 4 | 14 | -10 | 13,238 | 27,255 | -14,017 | 14,017 | 0 | 14,017 |
| Apr 27, 11 | 0 | 0 | 0 | 7,632 | 7,632 | 0 | 0 | 0 | 0 |
| Apr 28, 11 | 2 | 2 | 0 | 10,435 | 10,435 | 0 | 0 | 0 | 0 |
| Apr 29, 11 | 10 | 6 | 4 | 21,649 | 16,042 | 5,607 | 5,607 | 5,607 | 0 |
| Apr 30, 11 | 13 | 12 | 1 | 25,854 | 24,452 | 1,402 | 1,402 | 1,402 | 0 |
| May 1, 11 | 12 | 13 | -1 | 19,681 | 20,504 | -823 | 823 | 0 | 823 |
| May 2, 11 | 12 | 4 | 8 | 19,681 | 13,100 | 6,581 | 6,581 | 6,581 | 0 |
| May 3, 11 | 6 | 2 | 4 | 14,745 | 11,455 | 3,291 | 3,291 | 3,291 | 0 |
| May 4, 11 | 9 | 15 | -6 | 17,213 | 22,149 | -4,936 | 4,936 | 0 | 4,936 |
| May 5, 11 | 17 | 17 | 0 | 23,795 | 23,795 | 0 | 0 | 0 | 0 |
| May 6, 11 | 6 | 5 | 1 | 14,745 | 13,923 | 823 | 823 | 823 | 0 |
| May 7, 11 | 8 | 8 | 0 | 16,391 | 16,391 | 0 | 0 | 0 | 0 |
| May 8, 11 | 10 | 11 | -1 | 18,036 | 18,859 | -823 | 823 | 0 | 823 |
| May 9, 11 | 9 | 4 | 5 | 17,213 | 13,100 | 4,113 | 4,113 | 4,113 | 0 |
| May 10, 11 | 11 | 11 | 0 | 18,859 | 18,859 | 0 | 0 | 0 | 0 |
| May 11, 11 | 10 | 9 | 1 | 18,036 | 17,213 | 823 | 823 | 823 | 0 |
| May 12, 11 | 5 | 9 | -4 | 13,923 | 17,213 | -3,291 | 3,291 | 0 | 3,291 |
| May 13, 11 | 7 | 8 | -1 | 15,568 | 16,391 | -823 | 823 | 0 | 823 |
| May 14, 11 | 10 | 9 | 1 | 18,036 | 17,213 | 823 | 823 | 823 | 0 |
| May 15, 11 | 10 | 13 | -3 | 18,036 | 20,504 | -2,468 | 2,468 | 0 | 2,468 |
| May 16, 11 | 11 | 17 | -6 | 18,859 | 23,795 | -4,936 | 4,936 | 0 | 4,936 |
| May 17, 11 | 11 | 15 | -4 | 18,859 | 22,149 | -3,291 | 3,291 | 0 | 3,291 |
| May 18, 11 | 13 | 13 | 0 | 20,504 | 20,504 | 0 | 0 | 0 | 0 |
| May 19, 11 | 10 | 7 | 3 | 18,036 | 15,568 | 2,468 | 2,468 | 2,468 | 0 |
| May 20, 11 | 7 | 6 | 1 | 15,568 | 14,745 | 823 | 823 | 823 | 0 |
| May 21, 11 | 5 | 7 | -2 | 13,923 | 15,568 | -1,645 | 1,645 | 0 | 1,645 |
| May 22, 11 | 10 | 14 | -4 | 18,036 | 21,327 | -3,291 | 3,291 | 0 | 3,291 |
| May 23, 11 | 0 | 5 | -5 | 9,809 | 13,923 | -4,113 | 4,113 | 0 | 4,113 |
| May 24, 11 | 0 | 0 | 0 | 9,809 | 9,809 | 0 | 0 | 0 | 0 |
| May 25, 11 | 2 | 0 | 2 | 11,455 | 9,809 | 1,645 | 1,645 | 1,645 | 0 |
| May 26, 11 | 0 | 0 | 0 | 9,809 | 9,809 | 0 | 0 | 0 | 0 |
| May 27, 11 | 0 | 0 | 0 | 9,809 | 9,809 | 0 | 0 | 0 | 0 |
| May 28, 11 | 0 | 0 | 0 | 9,809 | 9,809 | 0 | 0 | 0 | 0 |
| May 29, 11 | 0 | 0 | 0 | 9,809 | 9,809 | 0 | 0 | 0 | 0 |
| May 30, 11 | 0 | 0 | 0 | 9,809 | 9,809 | 0 | 0 | 0 | 0 |
| May 31, 11 | 0 | 0 | 0 | 9,809 | 9,809 | 0 | 0 | 0 | 0 |
| Jun 1, 11 | 0 | 0 | 0 | 10,220 | 10,220 | 0 | 0 | 0 | 0 |
| Jun 2, 11 | 6 | 6 | 0 | 11,400 | 11,400 | 0 | 0 | 0 | 0 |
| Jun 3, 11 | 4 | 6 | -2 | 11,007 | 11,400 | -394 | 394 | 0 | 394 |
| Jun 4, 11 | 3 | 8 | -5 | 10,810 | 11,794 | -984 | 984 | 0 | 984 |
| Jun 5, 11 | 3 | 2 | 1 | 10,810 | 10,613 | 197 | 197 | 197 | 0 |
| Jun 6, 11 | 2 | 0 | 2 | 10,613 | 10,220 | 394 | 394 | 394 | 0 |
| Jun 7, 11 | 0 | 0 | 0 | 10,220 | 10,220 | 0 | 0 | 0 | 0 |
| Jun 8, 11 | 0 | 0 | 0 | 10,220 | 10,220 | 0 | 0 | 0 | 0 |
| Jun 9, 11 | 0 | 0 | 0 | 10,220 | 10,220 | 0 | 0 | 0 | 0 |
| Jun 10, 11 | 0 | 0 | 0 | 10,220 | 10,220 | 0 | 0 | 0 | 0 |
| Jun 11, 11 | 5 | 12 | -7 | 11,203 | 12,581 | -1,377 | 1,377 | 0 | 1,377 |
| Jun 12, 11 | 3 | 11 | -8 | 10,810 | 12,384 | -1,574 | 1,574 | 0 | 1,574 |
| Jun 13, 11 | 3 | 6 | -3 | 10,810 | 11,400 | -590 | 590 | 0 | 590 |
| Jun 14, 11 | 8 | 7 | 1 | 11,794 | 11,597 | 197 | 197 | 197 | 0 |
| Jun 15, 11 | 0 | 0 | 0 | 10,220 | 10,220 | 0 | 0 | 0 | 0 |
| Jun 16, 11 | 0 | 0 | 0 | 10,220 | 10,220 | 0 | 0 | 0 | 0 |
| Jun 17, 11 | 0 | 0 | 0 | 10,220 | 10,220 | 0 | 0 | 0 | 0 |
| Jun 18, 11 | 0 | 0 | 0 | 10,220 | 10,220 | 0 | 0 | 0 | 0 |
| Jun 19, 11 | 0 | 0 | 0 | 10,220 | 10,220 | 0 | 0 | 0 | 0 |
| Jun 20, 11 | 0 | 0 | 0 | 10,220 | 10,220 | 0 | 0 | 0 | 0 |
| Jun 21, 11 | 0 | 0 | 0 | 10,220 | 10,220 | 0 | 0 | 0 | 0 |
| Jun 22, 11 | 0 | 0 | 0 | 10,220 | 10,220 | 0 | 0 | 0 | 0 |
| Jun 23, 11 | 3 | 6 | -3 | 10,810 | 11,400 | -590 | 590 | 0 | 590 |
| Jun 24, 11 | 4 | 10 | -6 | 11,007 | 12,187 | -1,181 | 1,181 | 0 | 1,181 |
| Jun 25, 11 | 3 | 3 | 0 | 10,810 | 10,810 | 0 | 0 | 0 | 0 |
| Jun 26, 11 | 0 | 0 | 0 | 10,220 | 10,220 | 0 | 0 | 0 | 0 |
| Jun 27, 11 | 0 | 0 | 0 | 10,220 | 10,220 | 0 | 0 | 0 | 0 |
| Jun 28, 11 | 0 | 0 | 0 | 10,220 | 10,220 | 0 | 0 | 0 | 0 |
| Jun 29, 11 | 0 | 0 | 0 | 10,220 | 10,220 | 0 | 0 | 0 | 0 |
| Jun 30, 11 | 0 | 0 | 0 | 10,220 | 10,220 | 0 | 0 | 0 | 0 |
| Jul 1, 11 | 0 | 0 | 0 | 8,675 | 8,675 | 0 | 0 | 0 | 0 |
| Jul 2, 11 | 0 | 0 | 0 | 8,675 | 8,675 | 0 | 0 | 0 | 0 |
| Jul 3, 11 | 0 | 0 | 0 | 8,675 | 8,675 | 0 | 0 | 0 | 0 |
| Jul 4, 11 | 0 | 0 | 0 | 8,675 | 8,675 | 0 | 0 | 0 | 0 |

**EnergyNorth Natural Gas Inc.**

**Calculation of Supplier Balancing Charge**
**2011-12**
**Estimated Daily Imbalances**

| Date | Forecasted MAN HDD | Actual MAN HDD | Forecaster Error MAN HDD | Forecasted Sendout (MMBtu) | Actual Sendout (MMBtu) | Sendout Error (MMBtu) | Abs.Value Sendout Error (MMBtu) | Injections (MMBtu) | Withdrawals (MMBtu) |
|---|---|---|---|---|---|---|---|---|---|
| Jul 5, 11 | 0 | 0 | 0 | 8,675 | 8,675 | 0 | 0 | 0 | 0 |
| Jul 6, 11 | 0 | 0 | 0 | 8,675 | 8,675 | 0 | 0 | 0 | 0 |
| Jul 7, 11 | 0 | 0 | 0 | 8,675 | 8,675 | 0 | 0 | 0 | 0 |
| Jul 8, 11 | 0 | 0 | 0 | 8,675 | 8,675 | 0 | 0 | 0 | 0 |
| Jul 9, 11 | 0 | 0 | 0 | 8,675 | 8,675 | 0 | 0 | 0 | 0 |
| Jul 10, 11 | 0 | 0 | 0 | 8,675 | 8,675 | 0 | 0 | 0 | 0 |
| Jul 11, 11 | 0 | 0 | 0 | 8,675 | 8,675 | 0 | 0 | 0 | 0 |
| Jul 12, 11 | 0 | 0 | 0 | 8,675 | 8,675 | 0 | 0 | 0 | 0 |
| Jul 13, 11 | 0 | 0 | 0 | 8,675 | 8,675 | 0 | 0 | 0 | 0 |
| Jul 14, 11 | 0 | 0 | 0 | 8,675 | 8,675 | 0 | 0 | 0 | 0 |
| Jul 15, 11 | 0 | 0 | 0 | 8,675 | 8,675 | 0 | 0 | 0 | 0 |
| Jul 16, 11 | 0 | 0 | 0 | 8,675 | 8,675 | 0 | 0 | 0 | 0 |
| Jul 17, 11 | 0 | 0 | 0 | 8,675 | 8,675 | 0 | 0 | 0 | 0 |
| Jul 18, 11 | 0 | 0 | 0 | 8,675 | 8,675 | 0 | 0 | 0 | 0 |
| Jul 19, 11 | 0 | 0 | 0 | 8,675 | 8,675 | 0 | 0 | 0 | 0 |
| Jul 20, 11 | 0 | 0 | 0 | 8,675 | 8,675 | 0 | 0 | 0 | 0 |
| Jul 21, 11 | 0 | 0 | 0 | 8,675 | 8,675 | 0 | 0 | 0 | 0 |
| Jul 22, 11 | 0 | 0 | 0 | 8,675 | 8,675 | 0 | 0 | 0 | 0 |
| Jul 23, 11 | 0 | 0 | 0 | 8,675 | 8,675 | 0 | 0 | 0 | 0 |
| Jul 24, 11 | 0 | 0 | 0 | 8,675 | 8,675 | 0 | 0 | 0 | 0 |
| Jul 25, 11 | 0 | 0 | 0 | 8,675 | 8,675 | 0 | 0 | 0 | 0 |
| Jul 26, 11 | 0 | 0 | 0 | 8,675 | 8,675 | 0 | 0 | 0 | 0 |
| Jul 27, 11 | 0 | 0 | 0 | 8,675 | 8,675 | 0 | 0 | 0 | 0 |
| Jul 28, 11 | 0 | 0 | 0 | 8,675 | 8,675 | 0 | 0 | 0 | 0 |
| Jul 29, 11 | 0 | 0 | 0 | 8,675 | 8,675 | 0 | 0 | 0 | 0 |
| Jul 30, 11 | 0 | 0 | 0 | 8,675 | 8,675 | 0 | 0 | 0 | 0 |
| Jul 31, 11 | 0 | 0 | 0 | 8,675 | 8,675 | 0 | 0 | 0 | 0 |
| Aug 1, 11 | 0 | 0 | 0 | 9,107 | 9,107 | 0 | 0 | 0 | 0 |
| Aug 2, 11 | 0 | 0 | 0 | 9,107 | 9,107 | 0 | 0 | 0 | 0 |
| Aug 3, 11 | 0 | 0 | 0 | 9,107 | 9,107 | 0 | 0 | 0 | 0 |
| Aug 4, 11 | 0 | 0 | 0 | 9,107 | 9,107 | 0 | 0 | 0 | 0 |
| Aug 5, 11 | 0 | 0 | 0 | 9,107 | 9,107 | 0 | 0 | 0 | 0 |
| Aug 6, 11 | 0 | 0 | 0 | 9,107 | 9,107 | 0 | 0 | 0 | 0 |
| Aug 7, 11 | 0 | 0 | 0 | 9,107 | 9,107 | 0 | 0 | 0 | 0 |
| Aug 8, 11 | 0 | 0 | 0 | 9,107 | 9,107 | 0 | 0 | 0 | 0 |
| Aug 9, 11 | 0 | 0 | 0 | 9,107 | 9,107 | 0 | 0 | 0 | 0 |
| Aug 10, 11 | 0 | 0 | 0 | 9,107 | 9,107 | 0 | 0 | 0 | 0 |
| Aug 11, 11 | 0 | 0 | 0 | 9,107 | 9,107 | 0 | 0 | 0 | 0 |
| Aug 12, 11 | 0 | 0 | 0 | 9,107 | 9,107 | 0 | 0 | 0 | 0 |
| Aug 13, 11 | 0 | 0 | 0 | 9,107 | 9,107 | 0 | 0 | 0 | 0 |
| Aug 14, 11 | 0 | 0 | 0 | 9,107 | 9,107 | 0 | 0 | 0 | 0 |
| Aug 15, 11 | 0 | 2 | -2 | 9,107 | 10,082 | -976 | 976 | 0 | 976 |
| Aug 16, 11 | 0 | 0 | 0 | 9,107 | 9,107 | 0 | 0 | 0 | 0 |
| Aug 17, 11 | 0 | 0 | 0 | 9,107 | 9,107 | 0 | 0 | 0 | 0 |
| Aug 18, 11 | 0 | 0 | 0 | 9,107 | 9,107 | 0 | 0 | 0 | 0 |
| Aug 19, 11 | 0 | 0 | 0 | 9,107 | 9,107 | 0 | 0 | 0 | 0 |
| Aug 20, 11 | 0 | 0 | 0 | 9,107 | 9,107 | 0 | 0 | 0 | 0 |
| Aug 21, 11 | 0 | 0 | 0 | 9,107 | 9,107 | 0 | 0 | 0 | 0 |
| Aug 22, 11 | 0 | 0 | 0 | 9,107 | 9,107 | 0 | 0 | 0 | 0 |
| Aug 23, 11 | 0 | 0 | 0 | 9,107 | 9,107 | 0 | 0 | 0 | 0 |
| Aug 24, 11 | 0 | 0 | 0 | 9,107 | 9,107 | 0 | 0 | 0 | 0 |
| Aug 25, 11 | 0 | 0 | 0 | 9,107 | 9,107 | 0 | 0 | 0 | 0 |
| Aug 26, 11 | 0 | 0 | 0 | 9,107 | 9,107 | 0 | 0 | 0 | 0 |
| Aug 27, 11 | 0 | 0 | 0 | 9,107 | 9,107 | 0 | 0 | 0 | 0 |
| Aug 28, 11 | 0 | 0 | 0 | 9,107 | 9,107 | 0 | 0 | 0 | 0 |
| Aug 29, 11 | 0 | 0 | 0 | 9,107 | 9,107 | 0 | 0 | 0 | 0 |
| Aug 30, 11 | 0 | 0 | 0 | 9,107 | 9,107 | 0 | 0 | 0 | 0 |
| Aug 31, 11 | 0 | 0 | 0 | 9,107 | 9,107 | 0 | 0 | 0 | 0 |
| Sep 1, 11 | 0 | 0 | 0 | 9,626 | 9,626 | 0 | 0 | 0 | 0 |
| Sep 2, 11 | 0 | 1 | -1 | 9,626 | 10,001 | -375 | 375 | 0 | 375 |
| Sep 3, 11 | 0 | 0 | 0 | 9,626 | 9,626 | 0 | 0 | 0 | 0 |
| Sep 4, 11 | 0 | 0 | 0 | 9,626 | 9,626 | 0 | 0 | 0 | 0 |
| Sep 5, 11 | 0 | 0 | 0 | 9,626 | 9,626 | 0 | 0 | 0 | 0 |
| Sep 6, 11 | 3 | 2 | 1 | 10,750 | 10,376 | 375 | 375 | 375 | 0 |
| Sep 7, 11 | 3 | 7 | -4 | 10,750 | 12,249 | -1,499 | 1,499 | 0 | 1,499 |
| Sep 8, 11 | 1 | 0 | 1 | 10,001 | 9,626 | 375 | 375 | 375 | 0 |
| Sep 9, 11 | 0 | 0 | 0 | 9,626 | 9,626 | 0 | 0 | 0 | 0 |
| Sep 10, 11 | 2 | 3 | -1 | 10,376 | 10,750 | -375 | 375 | 0 | 375 |
| Sep 11, 11 | 1 | 1 | 0 | 10,001 | 10,001 | 0 | 0 | 0 | 0 |
| Sep 12, 11 | 0 | 0 | 0 | 9,626 | 9,626 | 0 | 0 | 0 | 0 |
| Sep 13, 11 | 0 | 0 | 0 | 9,626 | 9,626 | 0 | 0 | 0 | 0 |
| Sep 14, 11 | 0 | 0 | 0 | 9,626 | 9,626 | 0 | 0 | 0 | 0 |
| Sep 15, 11 | 9 | 8 | 1 | 12,999 | 12,624 | 375 | 375 | 375 | 0 |
| Sep 16, 11 | 15 | 13 | 2 | 15,247 | 14,498 | 750 | 750 | 750 | 0 |
| Sep 17, 11 | 10 | 9 | 1 | 13,374 | 12,999 | 375 | 375 | 375 | 0 |
| Sep 18, 11 | 10 | 11 | -1 | 13,374 | 13,748 | -375 | 375 | 0 | 375 |
| Sep 19, 11 | 7 | 8 | -1 | 12,249 | 12,624 | -375 | 375 | 0 | 375 |
| Sep 20, 11 | 5 | 7 | -2 | 11,500 | 12,249 | -750 | 750 | 0 | 750 |
| Sep 21, 11 | 0 | 0 | 0 | 9,626 | 9,626 | 0 | 0 | 0 | 0 |
| Sep 22, 11 | 0 | 0 | 0 | 9,626 | 9,626 | 0 | 0 | 0 | 0 |
| Sep 23, 11 | 0 | 0 | 0 | 9,626 | 9,626 | 0 | 0 | 0 | 0 |
| Sep 24, 11 | 0 | 0 | 0 | 9,626 | 9,626 | 0 | 0 | 0 | 0 |
| Sep 25, 11 | 0 | 0 | 0 | 9,626 | 9,626 | 0 | 0 | 0 | 0 |
| Sep 26, 11 | 0 | 0 | 0 | 9,626 | 9,626 | 0 | 0 | 0 | 0 |
| Sep 27, 11 | 0 | 0 | 0 | 9,626 | 9,626 | 0 | 0 | 0 | 0 |
| Sep 28, 11 | 3 | 0 | 3 | 10,750 | 9,626 | 1,124 | 1,124 | 1,124 | 0 |
| Sep 29, 11 | 1 | 2 | -1 | 10,001 | 10,376 | -375 | 375 | 0 | 375 |
| Sep 30, 11 | 2 | 0 | 2 | 10,376 | 9,626 | 750 | 750 | 750 | 0 |
| Oct 1, 11 | 4 | 8 | -4 | 10,156 | 15,323 | -5,167 | 5,167 | 0 | 5,167 |
| Oct 2, 11 | 11 | 6 | 5 | 19,198 | 12,739 | 6,459 | 6,459 | 6,459 | 0 |
| Oct 3, 11 | 10 | 7 | 3 | 17,906 | 14,031 | 3,875 | 3,875 | 3,875 | 0 |
| Oct 4, 11 | 9 | 9 | 0 | 16,615 | 16,615 | 0 | 0 | 0 | 0 |
| Oct 5, 11 | 17 | 16 | 1 | 26,949 | 25,657 | 1,292 | 1,292 | 1,292 | 0 |
| Oct 6, 11 | 20 | 17 | 3 | 30,824 | 26,949 | 3,875 | 3,875 | 3,875 | 0 |
| Oct 7, 11 | 13 | 12 | 1 | 21,782 | 20,490 | 1,292 | 1,292 | 1,292 | 0 |
| Oct 8, 11 | 0 | 2 | -2 | 4,989 | 7,572 | -2,584 | 2,584 | 0 | 2,584 |

**EnergyNorth Natural Gas Inc.**

**Calculation of Supplier Balancing Charge**
**2011-12**
**Estimated Daily Imbalances**

| Date | Forecasted MAN HDD | Actual MAN HDD | Forecaster Error MAN HDD | Forecasted Sendout (MMBtu) | Actual Sendout (MMBtu) | Sendout Error (MMBtu) | Abs.Value Sendout Error (MMBtu) | Injections (MMBtu) | Withdrawals (MMBtu) |
|---|---|---|---|---|---|---|---|---|---|
| Oct 9, 11 | 0 | 0 | 0 | 4,989 | 4,989 | 0 | 0 | 0 | 0 |
| Oct 10, 11 | 3 | 0 | 3 | 8,864 | 4,989 | 3,875 | 3,875 | 3,875 | 0 |
| Oct 11, 11 | 7 | 9 | -2 | 14,031 | 16,615 | -2,584 | 2,584 | 0 | 2,584 |
| Oct 12, 11 | 8 | 9 | -1 | 15,323 | 16,615 | -1,292 | 1,292 | 0 | 1,292 |
| Oct 13, 11 | 3 | 7 | -4 | 8,864 | 14,031 | -5,167 | 5,167 | 0 | 5,167 |
| Oct 14, 11 | 4 | 4 | 0 | 10,156 | 10,156 | 0 | 0 | 0 | 0 |
| Oct 15, 11 | 12 | 9 | 3 | 20,490 | 16,615 | 3,875 | 3,875 | 3,875 | 0 |
| Oct 16, 11 | 11 | 9 | 2 | 19,198 | 16,615 | 2,584 | 2,584 | 2,584 | 0 |
| Oct 17, 11 | 12 | 13 | -1 | 20,490 | 21,782 | -1,292 | 1,292 | 0 | 1,292 |
| Oct 18, 11 | 11 | 13 | -2 | 19,198 | 21,782 | -2,584 | 2,584 | 0 | 2,584 |
| Oct 19, 11 | 8 | 12 | -4 | 15,323 | 20,490 | -5,167 | 5,167 | 0 | 5,167 |
| Oct 20, 11 | 10 | 10 | 0 | 17,906 | 17,906 | 0 | 0 | 0 | 0 |
| Oct 21, 11 | 13 | 11 | 2 | 21,782 | 19,198 | 2,584 | 2,584 | 2,584 | 0 |
| Oct 22, 11 | 17 | 17 | 0 | 26,949 | 26,949 | 0 | 0 | 0 | 0 |
| Oct 23, 11 | 16 | 21 | -5 | 25,657 | 32,116 | -6,459 | 6,459 | 0 | 6,459 |
| Oct 24, 11 | 14 | 14 | 0 | 23,074 | 23,074 | 0 | 0 | 0 | 0 |
| Oct 25, 11 | 17 | 17 | 0 | 26,949 | 26,949 | 0 | 0 | 0 | 0 |
| Oct 26, 11 | 20 | 21 | -1 | 30,824 | 32,116 | -1,292 | 1,292 | 0 | 1,292 |
| Oct 27, 11 | 27 | 29 | -2 | 39,867 | 42,450 | -2,584 | 2,584 | 0 | 2,584 |
| Oct 28, 11 | 29 | 29 | 0 | 42,450 | 42,450 | 0 | 0 | 0 | 0 |
| Oct 29, 11 | 28 | 30 | -2 | 41,159 | 43,742 | -2,584 | 2,584 | 0 | 2,584 |
| Oct 30, 11 | 29 | 30 | -1 | 42,450 | 43,742 | -1,292 | 1,292 | 0 | 1,292 |
| Oct 31, 11 | 25 | 27 | -2 | 37,283 | 39,867 | -2,584 | 2,584 | 0 | 2,584 |
| Nov 1, 11 | 26 | 27 | -1 | 43,654 | 44,879 | -1,225 | 1,225 | 0 | 1,225 |
| Nov 2, 11 | 22 | 25 | -3 | 38,752 | 42,428 | -3,676 | 3,676 | 0 | 3,676 |
| Nov 3, 11 | 20 | 18 | 2 | 36,301 | 33,850 | 2,451 | 2,451 | 2,451 | 0 |
| Nov 4, 11 | 27 | 27 | 0 | 44,879 | 44,879 | 0 | 0 | 0 | 0 |
| Nov 5, 11 | 28 | 29 | -1 | 46,105 | 47,330 | -1,225 | 1,225 | 0 | 1,225 |
| Nov 6, 11 | 22 | 23 | -1 | 38,752 | 39,978 | -1,225 | 1,225 | 0 | 1,225 |
| Nov 7, 11 | 17 | 14 | 3 | 32,625 | 28,948 | 3,676 | 3,676 | 3,676 | 0 |
| Nov 8, 11 | 14 | 13 | 1 | 28,948 | 27,723 | 1,225 | 1,225 | 1,225 | 0 |
| Nov 9, 11 | 11 | 7 | 4 | 25,272 | 20,370 | 4,902 | 4,902 | 4,902 | 0 |
| Nov 10, 11 | 14 | 13 | 1 | 28,948 | 27,723 | 1,225 | 1,225 | 1,225 | 0 |
| Nov 11, 11 | 26 | 25 | 1 | 43,654 | 42,428 | 1,225 | 1,225 | 1,225 | 0 |
| Nov 12, 11 | 23 | 23 | 0 | 39,978 | 39,978 | 0 | 0 | 0 | 0 |
| Nov 13, 11 | 14 | 10 | 4 | 28,948 | 24,047 | 4,902 | 4,902 | 4,902 | 0 |
| Nov 14, 11 | 13 | 4 | 9 | 27,723 | 16,694 | 11,029 | 11,029 | 11,029 | 0 |
| Nov 15, 11 | 13 | 13 | 0 | 27,723 | 27,723 | 0 | 0 | 0 | 0 |
| Nov 16, 11 | 18 | 13 | 5 | 33,850 | 27,723 | 6,127 | 6,127 | 6,127 | 0 |
| Nov 17, 11 | 27 | 25 | 2 | 44,879 | 42,428 | 2,451 | 2,451 | 2,451 | 0 |
| Nov 18, 11 | 26 | 27 | -1 | 43,654 | 44,879 | -1,225 | 1,225 | 0 | 1,225 |
| Nov 19, 11 | 21 | 16 | 5 | 37,527 | 31,399 | 6,127 | 6,127 | 6,127 | 0 |
| Nov 20, 11 | 17 | 27 | -10 | 32,625 | 44,879 | -12,255 | 12,255 | 0 | 12,255 |
| Nov 21, 11 | 28 | 31 | -3 | 46,105 | 49,781 | -3,676 | 3,676 | 0 | 3,676 |
| Nov 22, 11 | 23 | 27 | -4 | 39,978 | 44,879 | -4,902 | 4,902 | 0 | 4,902 |
| Nov 23, 11 | 30 | 31 | -1 | 48,556 | 49,781 | -1,225 | 1,225 | 0 | 1,225 |
| Nov 24, 11 | 27 | 30 | -3 | 44,879 | 48,556 | -3,676 | 3,676 | 0 | 3,676 |
| Nov 25, 11 | 21 | 21 | 0 | 37,527 | 37,527 | 0 | 0 | 0 | 0 |
| Nov 26, 11 | 20 | 19 | 1 | 36,301 | 35,076 | 1,225 | 1,225 | 1,225 | 0 |
| Nov 27, 11 | 15 | 21 | -6 | 30,174 | 37,527 | -7,353 | 7,353 | 0 | 7,353 |
| Nov 28, 11 | 19 | 11 | 8 | 35,076 | 25,272 | 9,804 | 9,804 | 9,804 | 0 |
| Nov 29, 11 | 9 | 8 | 1 | 22,821 | 21,596 | 1,225 | 1,225 | 1,225 | 0 |
| Nov 30, 11 | 20 | 20 | 0 | 36,301 | 36,301 | 0 | 0 | 0 | 0 |
| Dec 1, 11 | 28 | 29 | -1 | 53,404 | 55,087 | -1,683 | 1,683 | 0 | 1,683 |
| Dec 2, 11 | 28 | 26 | 2 | 53,404 | 50,039 | 3,365 | 3,365 | 3,365 | 0 |
| Dec 3, 11 | 30 | 31 | -1 | 56,770 | 58,452 | -1,683 | 1,683 | 0 | 1,683 |
| Dec 4, 11 | 20 | 22 | -2 | 39,943 | 43,308 | -3,365 | 3,365 | 0 | 3,365 |
| Dec 5, 11 | 15 | 12 | 3 | 31,529 | 26,481 | 5,048 | 5,048 | 5,048 | 0 |
| Dec 6, 11 | 21 | 9 | 12 | 41,625 | 21,433 | 20,192 | 20,192 | 20,192 | 0 |
| Dec 7, 11 | 27 | 24 | 3 | 51,722 | 46,673 | 5,048 | 5,048 | 5,048 | 0 |
| Dec 8, 11 | 33 | 30 | 3 | 61,818 | 56,770 | 5,048 | 5,048 | 5,048 | 0 |
| Dec 9, 11 | 28 | 29 | -1 | 53,404 | 55,087 | -1,683 | 1,683 | 0 | 1,683 |
| Dec 10, 11 | 35 | 35 | 0 | 65,183 | 65,183 | 0 | 0 | 0 | 0 |
| Dec 11, 11 | 34 | 34 | 0 | 63,500 | 63,500 | 0 | 0 | 0 | 0 |
| Dec 12, 11 | 31 | 32 | -1 | 58,452 | 60,135 | -1,683 | 1,683 | 0 | 1,683 |
| Dec 13, 11 | 31 | 27 | 4 | 58,452 | 51,722 | 6,731 | 6,731 | 6,731 | 0 |
| Dec 14, 11 | 29 | 28 | 1 | 55,087 | 53,404 | 1,683 | 1,683 | 1,683 | 0 |
| Dec 15, 11 | 20 | 17 | 3 | 39,943 | 34,895 | 5,048 | 5,048 | 5,048 | 0 |
| Dec 16, 11 | 31 | 26 | 5 | 58,452 | 50,039 | 8,413 | 8,413 | 8,413 | 0 |
| Dec 17, 11 | 39 | 40 | -1 | 71,914 | 73,597 | -1,683 | 1,683 | 0 | 1,683 |
| Dec 18, 11 | 41 | 47 | -6 | 75,279 | 85,375 | -10,096 | 10,096 | 0 | 10,096 |
| Dec 19, 11 | 29 | 27 | 2 | 55,087 | 51,722 | 3,365 | 3,365 | 3,365 | 0 |
| Dec 20, 11 | 37 | 36 | 1 | 68,549 | 66,866 | 1,683 | 1,683 | 1,683 | 0 |
| Dec 21, 11 | 22 | 27 | -5 | 43,308 | 51,722 | -8,413 | 8,413 | 0 | 8,413 |
| Dec 22, 11 | 25 | 22 | 3 | 48,356 | 43,308 | 5,048 | 5,048 | 5,048 | 0 |
| Dec 23, 11 | 33 | 34 | -1 | 61,818 | 63,500 | -1,683 | 1,683 | 0 | 1,683 |
| Dec 24, 11 | 42 | 45 | -3 | 76,962 | 82,010 | -5,048 | 5,048 | 0 | 5,048 |
| Dec 25, 11 | 33 | 37 | -4 | 61,818 | 68,549 | -6,731 | 6,731 | 0 | 6,731 |
| Dec 26, 11 | 35 | 36 | -1 | 65,183 | 66,866 | -1,683 | 1,683 | 0 | 1,683 |
| Dec 27, 11 | 28 | 19 | 9 | 53,404 | 38,260 | 15,144 | 15,144 | 15,144 | 0 |
| Dec 28, 11 | 39 | 36 | 3 | 71,914 | 66,866 | 5,048 | 5,048 | 5,048 | 0 |
| Dec 29, 11 | 41 | 39 | 2 | 75,279 | 71,914 | 3,365 | 3,365 | 3,365 | 0 |
| Dec 30, 11 | 31 | 34 | -3 | 58,452 | 63,500 | -5,048 | 5,048 | 0 | 5,048 |
| Dec 31, 11 | 32 | 32 | 0 | 60,135 | 60,135 | 0 | 0 | 0 | 0 |
| Jan 1, 12 | 27 | 21 | 6 | 51,722 | 41,625 | 10,096 | 10,096 | 10,096 | 0 |
| Jan 2, 12 | 39 | 33 | 6 | 71,914 | 61,818 | 10,096 | 10,096 | 10,096 | 0 |
| Jan 3, 12 | 56 | 52 | 4 | 100,520 | 93,789 | 6,731 | 6,731 | 6,731 | 0 |
| Jan 4, 12 | 44 | 42 | 2 | 80,327 | 76,962 | 3,365 | 3,365 | 3,365 | 0 |
| Jan 5, 12 | 39 | 37 | 2 | 71,914 | 68,549 | 3,365 | 3,365 | 3,365 | 0 |
| Jan 6, 12 | 32 | 33 | -1 | 60,135 | 61,818 | -1,683 | 1,683 | 0 | 1,683 |
| Jan 7, 12 | 31 | 24 | 7 | 58,452 | 46,673 | 11,779 | 11,779 | 11,779 | 0 |
| Jan 8, 12 | 36 | 31 | 5 | 66,866 | 58,452 | 8,413 | 8,413 | 8,413 | 0 |
| Jan 9, 12 | 36 | 33 | 3 | 66,866 | 61,818 | 5,048 | 5,048 | 5,048 | 0 |
| Jan 10, 12 | 34 | 32 | 2 | 63,500 | 60,135 | 3,365 | 3,365 | 3,365 | 0 |
| Jan 11, 12 | 35 | 32 | 3 | 65,183 | 60,135 | 5,048 | 5,048 | 5,048 | 0 |
| Jan 12, 12 | 32 | 35 | -3 | 60,135 | 65,183 | -5,048 | 5,048 | 0 | 5,048 |

**EnergyNorth Natural Gas Inc.**

**Calculation of Supplier Balancing Charge**
**2011-12**
**Estimated Daily Imbalances**

| Date | Forecasted MAN HDD | Actual MAN HDD | Forecaster Error MAN HDD | Forecasted Sendout (MMBtu) | Actual Sendout (MMBtu) | Sendout Error (MMBtu) | Abs.Value Sendout Error (MMBtu) | Injections (MMBtu) | Withdrawals (MMBtu) |
|---|---|---|---|---|---|---|---|---|---|
| Jan 13, 12 | 34 | 34 | 0 | 63,500 | 63,500 | 0 | 0 | 0 | 0 |
| Jan 14, 12 | 53 | 51 | 2 | 95,472 | 92,106 | 3,365 | 3,365 | 3,365 | 0 |
| Jan 15, 12 | 54 | 57 | -3 | 97,154 | 102,202 | -5,048 | 5,048 | 0 | 5,048 |
| Jan 16, 12 | 37 | 37 | 0 | 68,549 | 68,549 | 0 | 0 | 0 | 0 |
| Jan 17, 12 | 28 | 26 | 2 | 53,404 | 50,039 | 3,365 | 3,365 | 3,365 | 0 |
| Jan 18, 12 | 45 | 44 | 1 | 82,010 | 80,327 | 1,683 | 1,683 | 1,683 | 0 |
| Jan 19, 12 | 39 | 42 | -3 | 71,914 | 76,962 | -5,048 | 5,048 | 0 | 5,048 |
| Jan 20, 12 | 45 | 45 | 0 | 82,010 | 82,010 | 0 | 0 | 0 | 0 |
| Jan 21, 12 | 47 | 53 | -6 | 85,375 | 95,472 | -10,096 | 10,096 | 0 | 10,096 |
| Jan 22, 12 | 37 | 40 | -3 | 68,549 | 73,597 | -5,048 | 5,048 | 0 | 5,048 |
| Jan 23, 12 | 25 | 32 | -7 | 48,356 | 60,135 | -11,779 | 11,779 | 0 | 11,779 |
| Jan 24, 12 | 30 | 24 | 6 | 56,770 | 46,673 | 10,096 | 10,096 | 10,096 | 0 |
| Jan 25, 12 | 36 | 31 | 5 | 66,866 | 58,452 | 8,413 | 8,413 | 8,413 | 0 |
| Jan 26, 12 | 32 | 30 | 2 | 60,135 | 56,770 | 3,365 | 3,365 | 3,365 | 0 |
| Jan 27, 12 | 32 | 27 | 5 | 60,135 | 51,722 | 8,413 | 8,413 | 8,413 | 0 |
| Jan 28, 12 | 31 | 27 | 4 | 58,452 | 51,722 | 6,731 | 6,731 | 6,731 | 0 |
| Jan 29, 12 | 33 | 31 | 2 | 61,818 | 58,452 | 3,365 | 3,365 | 3,365 | 0 |
| Jan 30, 12 | 40 | 36 | 4 | 73,597 | 66,866 | 6,731 | 6,731 | 6,731 | 0 |
| Jan 31, 12 | 30 | 33 | -3 | 56,770 | 61,818 | -5,048 | 5,048 | 0 | 5,048 |
| Feb 1, 12 | 26 | 23 | 3 | 50,039 | 44,991 | 5,048 | 5,048 | 5,048 | 0 |
| Feb 2, 12 | 34 | 36 | -2 | 63,500 | 66,866 | -3,365 | 3,365 | 0 | 3,365 |
| Feb 3, 12 | 36 | 34 | 2 | 66,866 | 63,500 | 3,365 | 3,365 | 3,365 | 0 |
| Feb 4, 12 | 38 | 38 | 0 | 70,231 | 70,231 | 0 | 0 | 0 | 0 |
| Feb 5, 12 | 36 | 36 | 0 | 66,866 | 66,866 | 0 | 0 | 0 | 0 |
| Feb 6, 12 | 29 | 25 | 4 | 55,087 | 48,356 | 6,731 | 6,731 | 6,731 | 0 |
| Feb 7, 12 | 36 | 36 | 0 | 66,866 | 66,866 | 0 | 0 | 0 | 0 |
| Feb 8, 12 | 37 | 34 | 3 | 68,549 | 63,500 | 5,048 | 5,048 | 5,048 | 0 |
| Feb 9, 12 | 33 | 33 | 0 | 61,818 | 61,818 | 0 | 0 | 0 | 0 |
| Feb 10, 12 | 30 | 25 | 5 | 56,770 | 48,356 | 8,413 | 8,413 | 8,413 | 0 |
| Feb 11, 12 | 41 | 39 | 2 | 75,279 | 71,914 | 3,365 | 3,365 | 3,365 | 0 |
| Feb 12, 12 | 48 | 48 | 0 | 87,058 | 87,058 | 0 | 0 | 0 | 0 |
| Feb 13, 12 | 39 | 35 | 4 | 71,914 | 65,183 | 6,731 | 6,731 | 6,731 | 0 |
| Feb 14, 12 | 32 | 30 | 2 | 60,135 | 56,770 | 3,365 | 3,365 | 3,365 | 0 |
| Feb 15, 12 | 27 | 31 | -4 | 51,722 | 58,452 | -6,731 | 6,731 | 0 | 6,731 |
| Feb 16, 12 | 25 | 25 | 0 | 48,356 | 48,356 | 0 | 0 | 0 | 0 |
| Feb 17, 12 | 28 | 26 | 2 | 53,404 | 50,039 | 3,365 | 3,365 | 3,365 | 0 |
| Feb 18, 12 | 31 | 29 | 2 | 58,452 | 55,087 | 3,365 | 3,365 | 3,365 | 0 |
| Feb 19, 12 | 36 | 33 | 3 | 66,866 | 61,818 | 5,048 | 5,048 | 5,048 | 0 |
| Feb 20, 12 | 36 | 35 | 1 | 66,866 | 65,183 | 1,683 | 1,683 | 1,683 | 0 |
| Feb 21, 12 | 29 | 29 | 0 | 55,087 | 55,087 | 0 | 0 | 0 | 0 |
| Feb 22, 12 | 23 | 20 | 3 | 44,991 | 39,943 | 5,048 | 5,048 | 5,048 | 0 |
| Feb 23, 12 | 25 | 26 | -1 | 48,356 | 50,039 | -1,683 | 1,683 | 0 | 1,683 |
| Feb 24, 12 | 30 | 29 | 1 | 56,770 | 55,087 | 1,683 | 1,683 | 1,683 | 0 |
| Feb 25, 12 | 35 | 34 | 1 | 65,183 | 63,500 | 1,683 | 1,683 | 1,683 | 0 |
| Feb 26, 12 | 36 | 37 | -1 | 66,866 | 68,549 | -1,683 | 1,683 | 0 | 1,683 |
| Feb 27, 12 | 28 | 25 | 3 | 53,404 | 48,356 | 5,048 | 5,048 | 5,048 | 0 |
| Feb 28, 12 | 33 | 31 | 2 | 61,818 | 58,452 | 3,365 | 3,365 | 3,365 | 0 |
| Feb 29, 12 | 30 | 34 | -4 | 56,770 | 63,500 | -6,731 | 6,731 | 0 | 6,731 |
| Mar 1, 12 | 36 | 43 | -7 | 62,573 | 73,054 | -10,482 | 10,482 | 0 | 10,482 |
| Mar 2, 12 | 31 | 36 | -5 | 55,086 | 62,573 | -7,487 | 7,487 | 0 | 7,487 |
| Mar 3, 12 | 27 | 29 | -2 | 49,096 | 52,091 | -2,995 | 2,995 | 0 | 2,995 |
| Mar 4, 12 | 35 | 33 | 2 | 61,075 | 58,080 | 2,995 | 2,995 | 2,995 | 0 |
| Mar 5, 12 | 43 | 41 | 2 | 73,054 | 70,059 | 2,995 | 2,995 | 2,995 | 0 |
| Mar 6, 12 | 37 | 35 | 2 | 64,070 | 61,075 | 2,995 | 2,995 | 2,995 | 0 |
| Mar 7, 12 | 22 | 14 | 8 | 41,609 | 29,630 | 11,979 | 11,979 | 11,979 | 0 |
| Mar 8, 12 | 16 | 11 | 5 | 32,625 | 25,138 | 7,487 | 7,487 | 7,487 | 0 |
| Mar 9, 12 | 31 | 29 | 2 | 55,086 | 52,091 | 2,995 | 2,995 | 2,995 | 0 |
| Mar 10, 12 | 33 | 32 | 1 | 58,080 | 56,583 | 1,497 | 1,497 | 1,497 | 0 |
| Mar 11, 12 | 21 | 19 | 2 | 40,112 | 37,117 | 2,995 | 2,995 | 2,995 | 0 |
| Mar 12, 12 | 15 | 7 | 8 | 31,127 | 19,148 | 11,979 | 11,979 | 11,979 | 0 |
| Mar 13, 12 | 12 | 8 | 4 | 26,635 | 20,646 | 5,990 | 5,990 | 5,990 | 0 |
| Mar 14, 12 | 20 | 25 | -5 | 38,614 | 46,101 | -7,487 | 7,487 | 0 | 7,487 |
| Mar 15, 12 | 22 | 26 | -4 | 41,609 | 47,599 | -5,990 | 5,990 | 0 | 5,990 |
| Mar 16, 12 | 19 | 24 | -5 | 37,117 | 44,604 | -7,487 | 7,487 | 0 | 7,487 |
| Mar 17, 12 | 18 | 22 | -4 | 35,620 | 41,609 | -5,990 | 5,990 | 0 | 5,990 |
| Mar 18, 12 | 7 | 5 | 2 | 19,148 | 16,154 | 2,995 | 2,995 | 2,995 | 0 |
| Mar 19, 12 | 7 | 9 | -2 | 19,148 | 22,143 | -2,995 | 2,995 | 0 | 2,995 |
| Mar 20, 12 | 6 | 0 | 6 | 17,651 | 8,667 | 8,984 | 8,984 | 8,984 | 0 |
| Mar 21, 12 | 0 | 0 | 0 | 8,667 | 8,667 | 0 | 0 | 0 | 0 |
| Mar 22, 12 | 0 | 0 | 0 | 8,667 | 8,667 | 0 | 0 | 0 | 0 |
| Mar 23, 12 | 11 | 4 | 7 | 25,138 | 14,656 | 10,482 | 10,482 | 10,482 | 0 |
| Mar 24, 12 | 14 | 17 | -3 | 29,630 | 34,122 | -4,492 | 4,492 | 0 | 4,492 |
| Mar 25, 12 | 17 | 24 | -7 | 34,122 | 44,604 | -10,482 | 10,482 | 0 | 10,482 |
| Mar 26, 12 | 27 | 33 | -6 | 49,096 | 58,080 | -8,984 | 8,984 | 0 | 8,984 |
| Mar 27, 12 | 33 | 27 | 6 | 58,080 | 49,096 | 8,984 | 8,984 | 8,984 | 0 |
| Mar 28, 12 | 22 | 22 | 0 | 41,609 | 41,609 | 0 | 0 | 0 | 0 |
| Mar 29, 12 | 26 | 26 | 0 | 47,599 | 47,599 | 0 | 0 | 0 | 0 |
| Mar 30, 12 | 27 | 24 | 3 | 49,096 | 44,604 | 4,492 | 4,492 | 4,492 | 0 |
| Mar 31, 12 | 25 | 27 | -2 | 46,101 | 49,096 | -2,995 | 2,995 | 0 | 2,995 |
| Apr | 495 | 505 | -10 | 922,785 | 936,802 | -14,017 | 109,331 | 47,657 | 61,674 |
| May | 211 | 222 | -11 | 477,671 | 486,721 | -9,049 | 51,828 | 21,389 | 30,439 |
| Jun | 47 | 77 | -30 | 315,837 | 321,740 | -5,903 | 7,477 | 787 | 6,690 |
| Jul | 0 | 0 | 0 | 268,914 | 268,914 | 0 | 0 | 0 | 0 |
| Aug | 0 | 2 | -2 | 282,306 | 283,281 | -976 | 976 | 0 | 976 |
| Sep | 72 | 72 | 0 | 315,766 | 315,766 | 0 | 8,245 | 4,122 | 4,122 |
| Oct | 408 | 418 | -10 | 681,695 | 694,613 | -12,918 | 72,340 | 29,711 | 42,629 |
| Nov | 611 | 598 | 13 | 1,102,514 | 1,086,584 | 15,931 | 99,262 | 57,596 | 41,666 |
| Dec | 948 | 922 | 26 | 1,790,147 | 1,746,397 | 43,750 | 144,712 | 94,231 | 50,481 |
| Jan | 1,149 | 1,105 | 44 | 2,128,369 | 2,054,331 | 74,039 | 171,635 | 122,837 | 48,798 |
| Feb | 947 | 916 | 31 | 1,775,887 | 1,723,724 | 52,164 | 92,548 | 72,356 | 20,192 |
| Mar | 660 | 652 | 8 | 1,256,941 | 1,244,962 | 11,979 | 167,707 | 89,843 | 77,864 |
| Total | 5,548 | 5,489 | 59 | 11,318,834 | 11,163,834 | 155,000 | 926,061 | 540,530 | 385,530 |
| Datacheck | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

## ENERGYNORTH NATURAL GAS, INC.

## Docket DE 98-124 Gas Restructuring
## Peaking Demand Rate

| | | | | | Source: |
|---|---|---|---|---|---|
| 1 | Peak Day | | 138,000 | Dekatherm | |
| 2 | | | | | |
| 3 | Pipeline MDQ | | | | Attachment B Page 2 of 3: EnergyNorth Capacity Resources |
| 4 | | PNGTS | 1,000 | Dekatherm | |
| 5 | | TGP NET-NE 95346 | 4,000 | | |
| 6 | | TGP FT-A (Z5-Z6) 2302 | 3,122 | | |
| 7 | | TGP FT-A (Z0-Z6) 8587 | 7,035 | | |
| 8 | | TGP FT-A (Z1-Z6) 8587 | 14,561 | | |
| 9 | | TGP FT-A (Z6-Z6) 42076 | 20,000 | | |
| | | TGP FT-A (Z6-Z6) 72694 | 4,000 | | |
| 10 | | | 53,718 | Dekatherm | |
| 11 | | | | | |
| 12 | Underground Storage MDQ | | | | Attachment B Page 3 of 3: EnergyNorth Capacity Resources |
| 13 | | TGP FT-A (Z4-Z6) 632 | 15,265 | Dekatherm | |
| 14 | | TGP FT-A (Z4-Z6) 8587 | 3,811 | | |
| 15 | | TGP FT-A (Z4-Z6) 11234 | 7,082 | | |
| 16 | | TGP FT-A (Z5-Z6) 11234 | 1,957 | | |
| 17 | | | 28,115 | | |
| 18 | | | | | |
| 19 | | | | | |
| 20 | Peaking MDQ | | 56,167 | Dekatherm | Line 1 - Line 10 - Line 18 |
| 21 | | | | | |
| 22 | | | | | |
| 23 | Peaking Costs | | | | |
| 23 | Gas Supply | | $4,296,040 | | Attachment B Page 3 Line 11 |
| 25 | Indirect Production & Storage Capacity | | $1,980,428 | | Summary Page Line 68 |
| 26 | Granite Ridge | | $0 | | Attachment B Page 3 Line 1 |
| 27 | Total | | $6,276,468 | | Sum Line 24 - 26 |
| 28 | | | | | |
| 29 | Annual Peaking Rate per MDQ | | $111.75 | | Line 27 divided by Line 20 |
| 30 | | | | | |
| 31 | **Monthly Peaking MDQ** | | **$18.62** | **/Dekatherm** | Line 29 divided by 6 month |

00000247

**ENERGY NORTH NATURAL GAS, INC.**

**Tennessee Allocations:**

| Resource Type | High Load Factor | Low Load Factor |
|---|---|---|
| Pipeline | 49.00% | 38.00% |
| Storage | 17.00% | 21.00% |
| Peaking | 34.00% | 41.00% |
| TOTAL: | 100.00% | 100.00% |

**Capacity Resources effective November 1, 2012:**

| Resource | Pipeline Company | Rate Schedule | Contract # | Peak MDQ/ MDWQ | Storage MSQ | Rate $/Dth/Month Demand | Storage Capacity | Termination Date | LDC Managed |
|---|---|---|---|---|---|---|---|---|---|
| **Pipeline** | | | | | | | | | |
| | ANE * | Supply at Waddington | | 4,000 | | $14.3482 | | 10/31/2017 | X |
| | Iroquois | RTS to Wright | 470-01 | 4,047 | | $6.5971 | | 11/01/2017 | |
| | TGP | NET-NE | 95346 | 4,000 | | $7.4396 | | 11/30/2012 | |
| | | | | | | | | | |
| | BP Canada Energy Co.** | Supply at Niagara | | 3,199 | | $0.0000 | | 03/31/2012 | X |
| | TGP | FT-A (Z5-Z6) | 2302 | 3,122 | | $7.4396 | | 10/31/2015 | |
| | | | | | | | | | |
| | TGP | FT-A (Z0-Z6) | 8587 | 7,035 | | $24.4547 | | 10/31/2015 | |
| | TGP | FT-A (Z1-Z6) | 8587 | 14,561 | | $21.6916 | | 10/31/2015 | |
| | | | | | | | | | |
| | TGP | FT-A (Z6-Z6) | 42076 | 20,000 | | $4.8846 | | 10/31/2015 | |
| | TGP | FT-A (Z6-Z6) | 72694 | 4,000 | | $12.1700 | | 10/31/2029 | |
| **Storage** | | | | | | | | | |
| | TGP | FS-MA (Storage) | 523*** | 21,844 | 1,560,391 | $1.5400 | $0.0211 | 10/31/2015 | |
| | TGP | FT-A (Z4-Z6) | 632 | 15,265 | | $8.4896 | | 10/31/2015 | |
| | TGP | FT-A (Z4-Z6) | 8587 | 3,811 | | $8.4896 | | 10/31/2015 | |
| | | | | | | | | | |
| | National Fuel | FSS-1 (Storage) | O02357*** | 6,098 | 670,800 | $2.4826 | $0.0381 | 03/31/2012 | |
| | National Fuel | FST (Transport) | N02358 | 6,098 | | $3.7805 | | 03/31/2012 | |
| | TGP | FT-A (Z4-Z6) | 11234 | 6,150 | | $8.4896 | | 10/31/2012 | |
| | | | | | | | | | |
| | Honeoye | SS-NY (Storage) | SS-NY*** | 1,957 | 245,280 | $4.4683 | $0.0000 | 04/01/2012 | X |
| | TGP | FT-A (Z5-Z6) | 11234 | 1,957 | | $7.4396 | | 10/31/2012 | |
| | | | | | | | | | |
| | Dominion | GSS (Storage) | 300076*** | 934 | 102,700 | $1.8788 | $0.0145 | 03/31/2012 | |
| | TGP | FT-A (Z4-Z6) | 11234 | 932 | | $8.4896 | | 10/31/2012 | |
| **Peaking** | | | | | | | | | |
| | Energy North | LNG/Propane**** | | 30,167 | - | $18.6200 | $0.0000 | | X |
| | TGP | FT-A (Z6-Z6) | 72694 | 26,000 | - | $12.1700 | $0.0000 | 10/31/2029 | X |

* Volumes and Demand Charges are based on MMBtu at the border.
**BP commodity price is based on Inside FERC at Niagara plus $.01 per Dth.
***All gas transferred for storage contracts will be based on LDC's monthly WACOG.
****All commodity volumes nominated will be invoiced at LDC's WACOG + fuel retention. Demand charge applicable for 6 months.

**Note:** **All capacity will be released at maximum tariff rates. Above rates are maximum tariff rates effective 11/01/08. Because rates can change, please refer to the applicable pipeline tariff for current rates.**

**Above capacity is for all customers in the Energy North Service territory with the exception of Berlin, NH. Any customers behind the Berlin citygate will be allocated 100% PNGTS capacity at a demand rate of $40.2456/dth.**

## ENERGYNORTH NATURAL GAS, INC.

### Docket 98-124 Gas Restructuring
### Peaking Demand Rate
### Peaking Costs

| | | Volume | Rate | Monthly Cost | Months/Year | Annual Cost | |
|---|---|---|---|---|---|---|---|
| 1 | Granite Ridge - 30 days @ 15,000/dt | [redacted] | | | | | |
| 2 | | | | | | | |
| 3 | | | | | | | |
| 4 | Concord Lateral | | | | | | |
| 5 | DOMAC * FLS 160 | | | | | | |
| 6 | | | | | | | |
| 7 | Subtotal | | | | | **$4,296,040** | * |
| 8 | | | | | | | |
| 9 | **Total** | | | | | **$4,296,040** | |
| 10 | | | | | | | |

* Contract currently being negotiated for an effective date of November 1, 2012.

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ATTACHMENT C

**CAPACITY ALLOCATORS**

| Rate Class | | Pipeline | Storage | Peaking | Total |
|---|---|---|---|---|---|
| G-41 | Low Annual /High Winter Use | 38.0% | 21.0% | 41.0% | 100.0% |
| G-51 | Low Annual /Low Winter Use | 49.0% | 17.0% | 34.0% | 100.0% |
| G-42 | Medium Annual / High Winter | 38.0% | 21.0% | 41.0% | 100.0% |
| G-52 | High Annual / Low Winter Use | 49.0% | 17.0% | 34.0% | 100.0% |
| G-43 | High Annual / High Winter | 38.0% | 21.0% | 41.0% | 100.0% |
| G-53 | High Annual / Load Factor < 90% | 49.0% | 17.0% | 34.0% | 100.0% |
| G-54 | High Annual / Load Factor < 90% | 49.0% | 17.0% | 34.0% | 100.0% |

**EnergyNorth Natural Gas, Inc**

# Calculation of Capacity Allocators
# Docket No DE 98-124

**Capacity Assignment Table**

| | | | % of Peak Day Requirement | | | |
|---|---|---|---|---|---|---|
| | | | **Pipeline** | **Storage** | **Peaking** | **Total** |
| **G-41** | **LAHW** | Low Annual C&I - High Winter Use | 38.0% | 21.0% | 41.0% | 100.0% |
| **G-51** | **LALW** | Low Annual C&I - Low Winter Use | 49.0% | 17.0% | 34.0% | 100.0% |
| **G-42** | **MAHW** | Medium C&I - High Winter Use | 38.0% | 21.0% | 41.0% | 100.0% |
| **G-52** | **MALW** | Medium C&I - Low Winter Use | 49.0% | 17.0% | 34.0% | 100.0% |
| **G-43** | **HAHW** | High Annual C&I - High Winter Use | 38.0% | 21.0% | 41.0% | 100.0% |
| **G-53** | **HALW90** | High Annual C&I - LF < 90% | 49.0% | 17.0% | 34.0% | 100.0% |
| **G-54** | **HALWG90** | High Annual C&I - LF > 90% | 49.0% | 17.0% | 34.0% | 100.0% |

| | | | | | |
|---|---|---|---|---|---|
| **HLF** | High Load Factor | 49% | 17% | 34% | 100% |
| **LLF** | Low Load Factor | 38% | 21% | 41% | 100% |
| | Total | 39% | 20% | 41% | 100% |

**EnergyNorth Natural Gas, Inc**

**Calculation of Capacity Allocators**
**Docket No DE 98-124**

**Allocation of Peak Day**

**Design Day Throughput Allocated to Rate Classes**

| Design DD | | | 72 | |
|---|---|---|---|---|
| | | Base load | Heat load | Total |
| HLF | R-1 RNSH | 132 | 562 | 693 |
| LLF | R-3 RSH | 3,712 | 61,094 | 64,806 |
| LLF | G-41 SL | 841 | 22,831 | 23,672 |
| HLF | G-51 SH | 636 | 1,968 | 2,604 |
| LLF | G-42 ML | 1,721 | 32,624 | 34,345 |
| HLF | G-52 MH | 1,263 | 2,836 | 4,099 |
| LLF | G-43 LL | 401 | 3,762 | 4,163 |
| HLF | G-53 LLL90 | 257 | 1,502 | 1,759 |
| HLF | G-54 LLG90 | 98 | 1,761 | 1,859 |
| | TOTAL | 9,060 | 128,940 | 138,000 |
| | HLF | 2,386 | 8,629 | 11,014 |
| | LLF | 6,675 | 120,311 | 126,986 |
| | Total | 9,060 | 128,940 | 138,000 |

**Allocate Class Design Day Throughput to Supply Sources**

| | Base Pipeline | Remaining Pipeline | Sub-total Pipeline | Storage | Peaking | Total |
|---|---|---|---|---|---|---|
| R-1 RNSH | 132 | 194 | 326 | 122 | 245 | 693 |
| R-3 RSH | 3,712 | 21,160 | 24,872 | 13,321 | 26,613 | 64,806 |
| G-41 SL | 841 | 7,908 | 8,748 | 4,978 | 9,945 | 23,672 |
| G-51 SH | 636 | 682 | 1,318 | 429 | 857 | 2,604 |
| G-42 ML | 1,721 | 11,299 | 13,020 | 7,114 | 14,211 | 34,345 |
| G-52 MH | 1,263 | 982 | 2,245 | 618 | 1,235 | 4,099 |
| G-43 LL | 401 | 1,303 | 1,704 | 820 | 1,639 | 4,163 |
| G-53 LLL90 | 257 | 520 | 777 | 328 | 654 | 1,759 |
| G-54 LLG90 | 98 | 610 | 708 | 384 | 767 | 1,859 |
| TOTAL | 9,060 | 44,658 | 53,718 | 28,115 | 56,167 | 138,000 |
| HLF | 2,386 | 2,988 | 5,374 | 1,881 | 3,759 | 11,014 |
| LLF | 6,675 | 41,669 | 48,344 | 26,234 | 52,408 | 126,986 |
| Total | 9,060 | 44,658 | 53,718 | 28,115 | 56,167 | 138,000 |

**% of Peak Day Requirement**

| | Pipeline | Storage | Peaking | Total |
|---|---|---|---|---|
| R-1 RNSH | 47.1% | 17.7% | 35.3% | 100.0% |
| R-3 RSH | 38.4% | 20.6% | 41.1% | 100.0% |
| G-41 SL | 37.0% | 21.0% | 42.0% | 100.0% |
| G-51 SH | 50.6% | 16.5% | 32.9% | 100.0% |
| G-42 ML | 37.9% | 20.7% | 41.4% | 100.0% |
| G-52 MH | 54.8% | 15.1% | 30.1% | 100.0% |
| G-43 LL | 40.9% | 19.7% | 39.4% | 100.0% |
| G-53 LLL90 | 44.2% | 18.6% | 37.2% | 100.0% |
| G-54 LLG90 | 38.1% | 20.7% | 41.3% | 100.0% |
| TOTAL | 38.9% | 20.4% | 40.7% | 100.0% |
| High Load Factor | 49% | 17% | 34% | 100% |
| Low Load Factor | 38% | 21% | 41% | 100% |
| Total | 39% | 20% | 41% | 100% |

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# EnergyNorth Natural Gas, Inc

## Calculation of Capacity Allocators
## Docket No DE 98-124

Allocate Design Day Sendout

**Calculate Design Day Throughput (BBTU)**

**Design DD** 72

| | Daily Baseload * 1000 | March Heating Factor * 1000 | Heat load (Heating Factor * Design DD) | Total |
|---|---|---|---|---|
| | | | | |
| **R-1 RNSH** | 132 | 8.032 | 578 | 710 |
| **R-3 RSH** | 3,712 | 873.932 | 62,923 | 66,635 |
| **G-41 SL** | 841 | 326.595 | 23,515 | 24,355 |
| **G-51 SH** | 636 | 28.148 | 2,027 | 2,663 |
| **G-42 ML** | 1,721 | 466.681 | 33,601 | 35,322 |
| **G-52 MH** | 1,263 | 40.568 | 2,921 | 4,184 |
| **G-43 LL** | 401 | 53.810 | 3,874 | 4,276 |
| **G-53 LLL90** | 257 | 21.492 | 1,547 | 1,804 |
| **G-54 LLG90** | 98 | 25.188 | 1,814 | 1,912 |
| **TOTAL** | 9,060 | 1,570.851 | 132,800 | 141,860 |

| | | | | |
|---|---|---|---|---|
| **HLF** | 2,386 | 123 | 8,887 | 11,272 |
| **LLF** | 6,675 | 1,447 | 123,913 | 130,588 |
| **Total** | 9,060 | 1,571 | 132,800 | 141,860 |

| | | |
|---|---|---|
| **Design Day from 2012-2013 Resource Plan** | | **138,000** |
| **Design Day from Billing Calculation** | | 141,860 |
| **Variance** | | (3,860) |

| Baseload as % of Total Class Load | Heat Load as % of Total |
|---|---|
| | |
| 19% | 0.435% |
| 6% | 47.382% |
| 3% | 17.707% |
| 24% | 1.526% |
| 5% | 25.302% |
| 30% | 2.199% |
| 9% | 2.917% |
| 14% | 1.165% |
| 5% | 1.366% |
| | 100.000% |

**Allocate Design Day Sendout to Rate Classes**

| Base Load | Heat Load | Total |
|---|---|---|
| | | |
| 132 | 562 | 693 |
| 3,712 | 61,094 | 64,806 |
| 841 | 22,831 | 23,672 |
| 636 | 1,968 | 2,604 |
| 1,721 | 32,624 | 34,345 |
| 1,263 | 2,836 | 4,099 |
| 401 | 3,762 | 4,163 |
| 257 | 1,502 | 1,759 |
| 98 | 1,761 | 1,859 |
| 9,060 | 128,940 | 138,000 |

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**EnergyNorth Natural Gas, Inc**

**Calculation of Capacity Allocators**
**Docket No DE 98-124**



**CALCULATION OF NORMAL SALES VOLUMES**

**Actual Volumes**

**Total Core Sales Volumes(000's) MMBTU**

| | | Nov-11 | Dec-11 | Jan-12 | Feb-12 | Mar-12 | Apr-12 | May-12 | Jun-12 | Jul-12 | Aug-11 | Sep-11 | Oct-11 | Total | Monthly Baseload (Jul+Aug)/2 | Daily Baseload |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| HLF | R-1 RNSH | 7 | 9 | 11 | 11 | 10 | 8 | 7 | 5 | 4 | 4 | 4 | 5 | 85 | 4.082 | 0.132 |
| LLF | R-3 RSH | 362 | 553 | 870 | 871 | 800 | 481 | 316 | 177 | 123 | 107 | 114 | 145 | 4,919 | 115.079 | 3.712 |
| LLF | G-41 SL | 106 | 182 | 243 | 324 | 282 | 158 | 95 | 53 | 29 | 23 | 25 | 34 | 1,555 | 26.057 | 0.841 |
| HLF | G-51 SH | 28 | 36 | 33 | 45 | 42 | 32 | 29 | 23 | 21 | 18 | 19 | 22 | 347 | 19.718 | 0.636 |
| LLF | G-42 ML | 188 | 290 | 219 | 455 | 419 | 258 | 171 | 94 | 59 | 48 | 54 | 75 | 2,330 | 53.336 | 1.721 |
| HLF | G-52 MH | 51 | 61 | 32 | 74 | 71 | 57 | 51 | 45 | 40 | 39 | 39 | 42 | 603 | 39.144 | 1.263 |
| LLF | G-43 LL | 3 | 23 | 5 | 60 | 55 | 51 | 43 | 30 | 16 | 8 | 15 | (5) | 305 | 12.442 | 0.401 |
| HLF | G-53 LLL90 | 9 | 8 | (1) | 23 | 25 | 24 | 15 | 15 | 14 | 2 | 11 | (3) | 142 | 7.965 | 0.257 |
| HLF | G-54 LLL110 | 11 | 4 | 10 | 9 | 23 | 6 | 4 | 17 | 10 | (4) | 16 | 5 | 110 | 3.043 | 0.098 |
| HLF | G-63 LLG110 | - | - | - | - | - | - | - | - | - | - | - | - | 0 | 0.000 | 0.000 |
| | TOTAL | 767 | 1,165 | 1,421 | 1,872 | 1,727 | 1,076 | 731 | 459 | 317 | 245 | 298 | 319 | 10,397 | 280.866 | 9.060 |
| | | | | | | | | | | | | | | | | |
| | HLF | 106 | 118 | 84 | 162 | 171 | 126 | 107 | 106 | 89 | 59 | 90 | 70 | 1,287 | 73.953 | 2.386 |
| | LLF | 660 | 1,048 | 1,337 | 1,710 | 1,556 | 949 | 625 | 353 | 228 | 186 | 208 | 249 | 9,109 | 206.913 | 6.675 |

**Baseload (= the lesser of actual volumes or the average of July and August volumes)**

| | | Nov-11 | Dec-11 | Jan-12 | Feb-12 | Mar-12 | Apr-12 | May-12 | Jun-12 | Jul-12 | Aug-11 | Sep-11 | Oct-11 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 30 | 31 | 31 | 28 | 31 | 30 | 31 | 30 | 31 | 31 | 30 | 31 | 365 |
| HLF | R-1 RNSH | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 48 |
| LLF | R-3 RSH | 111 | 115 | 115 | 104 | 115 | 111 | 115 | 111 | 123 | 107 | 111 | 115 | 1,355 |
| LLF | G-41 SL | 25 | 26 | 26 | 24 | 26 | 25 | 26 | 25 | 29 | 23 | 25 | 26 | 307 |
| HLF | G-51 SH | 19 | 20 | 20 | 18 | 20 | 19 | 20 | 19 | 21 | 18 | 19 | 20 | 232 |
| LLF | G-42 ML | 52 | 53 | 53 | 48 | 53 | 52 | 53 | 52 | 59 | 48 | 52 | 53 | 628 |
| HLF | G-52 MH | 38 | 39 | 32 | 35 | 39 | 38 | 39 | 38 | 40 | 39 | 38 | 39 | 461 |
| LLF | G-43 LL | 3 | 12 | 5 | 11 | 12 | 12 | 12 | 12 | 16 | 8 | 12 | (5) | 146 |
| HLF | G-53 LLL90 | 8 | 8 | (1) | 7 | 8 | 8 | 8 | 8 | 14 | 2 | 8 | (3) | 94 |
| HLF | G-54 LLL110 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 10 | (4) | 3 | 3 | 36 |
| HLF | G-63 LLG110 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | TOTAL | 293 | 311 | 288 | 282 | 312 | 302 | 312 | 302 | 348 | 276 | 301 | 284 | 3,307 |
| | | | | | | | | | | | | | | |
| | HLF | 72 | 74 | 57 | 67 | 74 | 72 | 74 | 72 | 89 | 59 | 71 | 63 | 871 |
| | LLF | 192 | 207 | 199 | 187 | 207 | 200 | 207 | 200 | 228 | 186 | 200 | 189 | 2,436 |

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**EnergyNorth Natural Gas, Inc**

**Calculation of Capacity Allocators**
**Docket No DE 98-124**



**Heating Volumes (= Actual Volumes - Baseload)**

| | | Nov-11 | Dec-11 | Jan-12 | Feb-12 | Mar-12 | Apr-12 | May-12 | Jun-12 | Jul-12 | Aug-11 | Sep-11 | Oct-11 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| HLF | R-1 RNSH | 3 | 5 | 7 | 8 | 6 | 4 | 3 | 1 | 0 | 0 | 0 | 0 | 37 |
| LLF | R-3 RSH | 251 | 438 | 755 | 767 | 685 | 370 | 201 | 65 | 0 | 0 | 3 | 30 | 3,565 |
| LLF | G-41 SL | 81 | 156 | 217 | 300 | 256 | 133 | 69 | 28 | 0 | 0 | 0 | 8 | 1,248 |
| HLF | G-51 SH | 9 | 16 | 13 | 27 | 22 | 12 | 9 | 4 | 0 | 0 | 0 | 2 | 115 |
| LLF | G-42 ML | 137 | 236 | 166 | 407 | 366 | 207 | 118 | 42 | 0 | 0 | 3 | 21 | 1,702 |
| HLF | G-52 MH | 13 | 22 | 0 | 39 | 32 | 19 | 12 | 7 | 0 | 0 | 1 | 3 | 142 |
| LLF | G-43 LL | 0 | 11 | 0 | 49 | 42 | 39 | 30 | 18 | 0 | 0 | 3 | 0 | 158 |
| HLF | G-53 LLL90 | 1 | 0 | 0 | 15 | 17 | 17 | 7 | 7 | 0 | 0 | 4 | 0 | 48 |
| HLF | G-54 LLL110 | 8 | 1 | 6 | 6 | 20 | 3 | 1 | 14 | 0 | 0 | 13 | 2 | 75 |
| HLF | G-63 LLG110 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | TOTAL | 473 | 854 | 1,133 | 1,590 | 1,415 | 774 | 420 | 157 | (31) | (31) | (3) | 35 | 7,090 |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| HLF | 35 | 44 | 27 | 95 | 97 | 55 | 33 | 34 | 0 | 0 | 19 | 7 | 417 |
| LLF | 469 | 841 | 1,137 | 1,523 | 1,349 | 749 | 418 | 153 | 0 | 0 | 8 | 59 | 6,673 |

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Actual BDD** | **500.0** | **752.0** | **1015.5** | **1012.5** | **784.0** | **542.5** | **293.5** | **116.0** | **39.0** | **1.0** | **36.5** | **244.5** | 5337.0 |

**Heat Factors**

| | | Nov-11 | Dec-11 | Jan-12 | Feb-12 | Mar-12 | Apr-12 | May-12 | Jun-12 | Jul-12 | Aug-11 | Sep-11 | Oct-11 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| HLF | R-1 RNSH | 0.0056 | 0.0060 | 0.0071 | 0.0074 | 0.0080 | 0.0068 | 0.0093 | 0.0125 | 0.0000 | 0.0000 | 0.0030 | 0.0019 | |
| LLF | R-3 RSH | 0.5020 | 0.5818 | 0.7434 | 0.7577 | 0.8739 | 0.6818 | 0.6852 | 0.5622 | 0.0000 | 0.0000 | 0.0733 | 0.1217 | |
| LLF | G-41 SL | 0.1618 | 0.2077 | 0.2132 | 0.2967 | 0.3266 | 0.2453 | 0.2334 | 0.2387 | 0.0000 | 0.0000 | 0.0010 | 0.0344 | |
| HLF | G-51 SH | 0.0174 | 0.0215 | 0.0130 | 0.0272 | 0.0281 | 0.0229 | 0.0323 | 0.0376 | 0.0000 | 0.0000 | 0.0000 | 0.0079 | |
| LLF | G-42 ML | 0.2737 | 0.3143 | 0.1632 | 0.4017 | 0.4667 | 0.3813 | 0.4020 | 0.3631 | 0.0000 | 0.0000 | 0.0741 | 0.0866 | |
| HLF | G-52 MH | 0.0266 | 0.0296 | 0.0000 | 0.0385 | 0.0406 | 0.0356 | 0.0417 | 0.0637 | 0.0000 | 0.0000 | 0.0404 | 0.0111 | |
| LLF | G-43 LL | 0.0000 | 0.0140 | 0.0000 | 0.0484 | 0.0538 | 0.0725 | 0.1033 | 0.1525 | 0.0000 | 0.0000 | 0.0735 | 0.0000 | |
| HLF | G-53 LLL90 | 0.0030 | 0.0000 | 0.0000 | 0.0151 | 0.0215 | 0.0308 | 0.0247 | 0.0631 | 0.0000 | 0.0000 | 0.1037 | 0.0000 | |
| HLF | G-54 LLL110 | 0.0168 | 0.0019 | 0.0064 | 0.0058 | 0.0252 | 0.0049 | 0.0032 | 0.1177 | 0.0000 | 0.0000 | 0.3664 | 0.0085 | |
| HLF | G-63 LLG110 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | |
| | TOTAL | 0.9469 | 1.1357 | 1.1157 | 1.5709 | 1.8049 | 1.4266 | 1.4295 | 1.3525 | -0.7949 | -31.0000 | -0.0865 | 0.1452 | |

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**EnergyNorth Natural Gas, Inc**

**Calculation of Capacity Allocators**
**Docket No DE 98-124**



| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Actual BillingDD** | **500.0** | **752.0** | **1015.5** | **1012.5** | **784.0** | **542.5** | **293.5** | **116.0** | **39.0** | **1.0** | **36.5** | **244.5** | **5337.0** |
| **Norm Billing DD** | **566.1** | **884.1** | **1147.8** | **1143.1** | **976.2** | **709.1** | **380.6** | **148.5** | **28.9** | **8.4** | **61.7** | **268.3** | **6322.8** |

**Normal Volumes (= Heating Volumes * Normal EDD/Actual EDD + Baseload)**

| | | Nov-11 | Dec-11 | Jan-12 | Feb-12 | Mar-12 | Apr-12 | May-12 | Jun-12 | Jul-12 | Aug-11 | Sep-11 | Oct-11 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **HLF** | **R-1 RNSH** | 7 | 9 | 12 | 12 | 12 | 9 | 8 | 6 | 4 | 4 | 4 | 5 | 92 |
| **LLF** | **R-3 RSH** | 396 | 629 | 968 | 970 | 968 | 595 | 376 | 195 | 123 | 107 | 116 | 148 | 5,591 |
| **LLF** | **G-41 SL** | 117 | 210 | 271 | 363 | 345 | 199 | 115 | 61 | 29 | 23 | 25 | 35 | 1,792 |
| **HLF** | **G-51 SH** | 29 | 39 | 35 | 49 | 47 | 35 | 32 | 25 | 21 | 18 | 19 | 22 | 370 |
| **LLF** | **G-42 ML** | 207 | 331 | 241 | 507 | 509 | 322 | 206 | 106 | 59 | 48 | 56 | 77 | 2,668 |
| **HLF** | **G-52 MH** | 53 | 65 | 32 | 79 | 79 | 63 | 55 | 47 | 40 | 39 | 40 | 42 | 634 |
| **LLF** | **G-43 LL** | 3 | 25 | 5 | 67 | 65 | 63 | 52 | 35 | 16 | 8 | 17 | (5) | 351 |
| **HLF** | **G-53 LLL90** | 9 | 8 | (1) | 24 | 29 | 30 | 17 | 17 | 14 | 2 | 14 | (3) | 160 |
| **HLF** | **G-54 LLL110** | 12 | 5 | 10 | 9 | 28 | 6 | 4 | 20 | 10 | (4) | 26 | 5 | 133 |
| **HLF** | **G-63 LLG110** | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | **TOTAL** | 829 | 1,315 | 1,568 | 2,077 | 2,074 | 1,313 | 856 | 503 | 325 | 16 | 296 | 323 | 11,496 |

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **HLF** | 111 | 126 | 87 | 174 | 194 | 143 | 116 | 115 | 89 | 59 | 103 | 71 | 1,389 |
| **LLF** | 722 | 1,195 | 1,485 | 1,907 | 1,887 | 1,179 | 749 | 396 | 228 | 186 | 214 | 255 | 10,402 |

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**ENERGY NORTH NATURAL GAS, INC.**

**Peak 2012 - 2013 Winter Cost of Gas Filing**
**Fixed Price Option**

| | | Participation | Premium | FPO Volumes | Premium Revenue | FPO Rate | Residential Average COG Rate | Residential Total Bill FPO Rate | Residential Total Bill COG Rate | Difference | % Difference | FPO Rate | C&I Average COG Rate | C&I Total Bill FPO Rate | C&I Total Bill COG Rate | Difference | % Difference |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Nov 98 - Mar 99 | 6% | | | | $0.3927 | $0.3722 | $ 943.37 | $ 926.93 | $ 16.44 | 1.77% | $0.3927 | $0.3736 | $ 1,570.86 | $ 1,546.08 | $ 24.79 | 1.60% |
| 2 | Nov 99 - Mar 00 | 9% | | | | $0.4724 | $0.4628 | $ 679.85 | $ 672.22 | $ 7.63 | 1.13% | $0.4724 | $0.4636 | $ 1,161.81 | $ 1,149.15 | $ 12.67 | 1.10% |
| 3 | Nov 00 - Mar 01 | 20% | | | | $0.6408 | $0.7656 | $ 816.25 | $ 916.09 | $ (99.84) | -10.90% | $0.6408 | $0.7189 | $ 1,376.64 | $ 1,533.43 | $ (156.79) | -10.22% |
| 4 | Nov 01 - Apr 02 | 24% | | | | $0.5141 | $0.4818 | $ 790.65 | $ 760.55 | $ 30.10 | 3.96% | $0.5238 | $0.4928 | $ 1,301.07 | $ 1,256.88 | $ 44.19 | 3.52% |
| 5 | Nov 02 - Apr 03 | 24% | $0.0051 | 25,107,016 | $ 128,046 | $0.5553 | $0.5758 | $ 821.32 | $ 840.44 | $ (19.11) | -2.27% | $0.5658 | $0.5860 | $ 1,344.02 | $ 1,372.86 | $ (28.84) | -2.10% |
| 6 | Nov 03 - Apr 04 | 23% | $0.0219 | 25,220,575 | $ 552,331 | $0.8597 | $0.8220 | $ 1,115.55 | $ 1,080.46 | $ 35.09 | 3.25% | $0.8759 | $0.8352 | $ 1,798.38 | $ 1,740.30 | $ 58.08 | 3.34% |
| 7 | Nov 04 - Apr 05 | 30% | $0.0100 | 27,378,128 | $ 273,781 | $0.8925 | $0.9425 | $ 1,142.96 | $ 1,189.55 | $ (46.60) | -3.92% | $0.9092 | $0.9562 | $ 1,844.75 | $ 1,911.86 | $ (67.10) | -3.51% |
| 8 | Nov 05 - Apr 06 | 30% | $0.0200 | 25,944,091 | $ 518,882 | $1.2951 | $1.1342 | $ 1,526.01 | $ 1,376.01 | $ 150.00 | 10.90% | $1.3192 | $1.1686 | $ 2,450.66 | $ 2,235.77 | $ 214.89 | 9.61% |
| 9 | Nov 06 - Apr 07 | 15% | $0.0200 | 13,135,684 | $ 262,714 | $1.2664 | $1.1656 | $ 1,509.79 | $ 1,415.80 | $ 93.99 | 6.64% | $1.2666 | $1.1647 | $ 2,321.15 | $ 2,175.70 | $ 145.45 | 6.68% |
| 10 | Nov 07 - Apr 08 | 16% | $0.0200 | 14,078,553 | $ 281,571 | $1.2043 | $1.1746 | $ 1,433.09 | $ 1,405.40 | $ 27.69 | 1.97% | $1.2044 | $1.1725 | $ 2,232.39 | $ 2,186.92 | $ 45.47 | 2.08% |
| 11 | Nov 08 - Apr 09 | 15% | $0.0200 | 13,041,335 | $ 260,827 | $1.2835 | $1.0888 | $ 1,555.31 | $ 1,373.85 | $ 181.46 | 13.21% | $1.2836 | $1.0958 | $ 2,467.49 | $ 2,199.54 | $ 267.95 | 12.18% |
| 12 | Nov 09 - Apr 10 | 11% | $0.0200 | 8,405,413 | $ 168,108 | $0.9863 | $0.9416 | $ 1,250.80 | $ 1,209.12 | $ 41.69 | 3.45% | $0.9865 | $0.9408 | $ 1,984.29 | $ 1,919.03 | $ 65.26 | 3.40% |
| 13 | Nov 10 - Apr 11 | 13% | $0.0200 | 10,379,804 | $ 207,596 | $0.8420 | $0.8029 | $ 1,175.03 | $ 1,138.58 | $ 36.45 | 3.20% | $0.8434 | $0.8030 | $ 1,880.96 | $ 1,823.34 | $ 57.63 | 3.16% |
| 14 | Nov 11 - Apr 12 | 12% | $0.0200 | 7,835,197 | $ 156,704 | $0.8126 | $0.7309 | $ 1,165.61 | $ 1,089.44 | $ 76.17 | 6.99% | $0.8129 | $0.7327 | $ 1,845.28 | $ 1,730.88 | $ 114.40 | 6.61% |
| 15 | Nov 12 - Apr 13 | | | | | $0.6919 | $0.6719 | $ 1,012.23 | $ 993.59 | $ 18.64 | 1.88% | $0.6936 | $0.6736 | $ 1,630.78 | $ 1,602.24 | $ 28.54 | 1.78% |
| 16 | | | | | | | | | | | | | | | | | |
| 17 | Total | | | | | | | | | $ 549.79 | | | | | | $ 826.58 | |

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**ENERGY NORTH NATURAL GAS, INC.**

**Peak 2012 - 2013 Winter Cost of Gas Filing**
**Short Term Debt Limitations**

| | | For Purposes of Fuel Financing |
|---|---|---|
| Total Direct Gas Costs | $ | 48,820,141 |
| Total Indirect Gas Costs | | 3,420,439 |
| Total Gas Costs | $ | 52,240,580 |
| % of Debt to Total Gas Costs | | 30% |
| Short Term Debt | $ | 15,672,174 |

| | | For Purposes Other Than Fuel Financing |
|---|---|---|
| 12/1/2012 Projected Net Plant | $ | 229,685,196 |
| % of Debt to Net Plant | | 20% |
| Short Term Debt | $ | 45,937,039 |

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**ENERGY NORTH NATURAL GAS, INC.**

**Peak 2012 - 2013 Winter Cost of Gas Filing**

**EnergyNorth 2012-13 Company Allowance Calculation**

| | Jul-2011 | Aug-2011 | Sep-2011 | Oct-2011 | Nov-2011 | Dec-2011 | Jan-2012 | Feb-2012 | Mar-2012 | Apr-2012 | May-2012 | Jun-2012 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Total Sendout- Therms | 4,519,480 | 4,862,620 | 5,078,100 | 9,249,660 | 13,393,530 | 19,805,400 | 23,983,650 | 19,905,220 | 14,923,140 | 10,268,990 | 6,999,830 | 5,419,530 | 138,409,150 |
| Total Throughput- Therms | 5,225,388 | 4,475,390 | 4,900,963 | 5,494,651 | 10,195,273 | 14,469,371 | 21,154,186 | 21,484,340 | 19,742,635 | 13,028,434 | 9,558,538 | 6,530,049 | 136,259,218 |
| Variance | (705,908) | 387,230 | 177,137 | 3,755,009 | 3,198,257 | 5,336,029 | 2,829,464 | (1,579,120) | (4,819,495) | (2,759,444) | (2,558,708) | (1,110,519) | 2,149,932 |
| Company Allowance | | | | | | | | | | | | | **1.6%** |

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